

Public



Alaska LNG Liquefaction Plant Construction Permit
Application

Project Information Form Attachment 4:

Alaska LNG Resource Report 9 (Air and Noise Quality)

and

**Appendix H to RR9 (Project NSPS, NESHAPS and RMP
Applicability Analysis)**

March 2018

Alaska LNG
3201 C Street, Suite 200
Anchorage, Alaska 99503
T: 907-330-6300
www.alaska-lng.com

ALASKA LNG

**DOCKET NO. CP17-____-000
RESOURCE REPORT NO. 9
AIR AND NOISE QUALITY
PUBLIC**

DOCUMENT NUMBER: USAI-PE-SRREG-00-000009-000

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RESOURCE REPORT NO. 9 SUMMARY OF FILING INFORMATION ¹	
FILING REQUIREMENT	FOUND IN SECTION
1. Describe existing air quality in the vicinity of the project – Title 18 Code of Federal Regulations (CFR) part (§) 380.12 (k) (1).	9.2.2, Appendix B
2. Quantify the existing noise levels (day-night sound level (Ldn) and other applicable noise parameters) at noise sensitive areas and at other areas covered by relevant state and local noise ordinances – 18 CFR § 380.12 (k) (2)	9.3.1
3. Quantify existing and proposed emissions of compressor equipment, plus construction emissions, including nitrogen oxides (NOx) and carbon monoxide (CO), and the basis for these calculations. Summarize anticipated air quality impacts for the project – 18 CFR § 380.12 (k) (3)	9.2.3, 9.2.5 Appendix C Appendix E
4. Describe the existing compressor units at each station where new, additional, or modified compression units are proposed, including the manufacturer, model number, and horsepower of the compressor units. For proposed, new, additional, or modified compressor units, include horsepower, type, and energy source – 18 CFR § 380.12 (k) (4)	9.2.5 Appendix E
5. Identify any nearby noise-sensitive area by distance and direction from the proposed compressor unit building/enclosure – 18 CFR § 380.12 (k) (4)	9.3.1
6. Identify any applicable state or local noise regulations – 18 CFR § 380.12 (k) (4).	9.3.3, 9.3.5
7. Calculate the noise impact at noise-sensitive areas of the proposed compressor unit modifications or additions, specifying how the impact was calculated, including manufacturer's data and proposed noise control equipment – 18 CFR § 380.12 (k) (4)	9.3.4
ADDITIONAL INFORMATION OFTEN MISSING AND RESULTING IN DATA REQUESTS	
Air Quality Information	
Include climate information as part of the air quality information provided for the project area.	9.2.1
Identify potentially applicable federal and state air quality regulations.	9.2.4, 9.2.6
Provide construction emissions (criteria pollutants, hazardous air pollutants, greenhouse gases) for proposed pipelines and aboveground facilities.	9.2.3, Appendix C
Provide copies of state and federal applications for air permits.	Not available at this time
Provide operation and fugitive emissions (criteria pollutants, hazardous air pollutants, greenhouse gases) for pipelines and aboveground facilities.	9.2.5, Appendices D, E, F
Provide air modeling for entire compressor stations.	9.2.5, Appendix E
Identify temporary and permanent emissions sources that may have cumulative air quality effects in addition to those resulting from the project.	9.2.5, Appendices D, E, F
Noise and Vibration Information	
Describe the existing noise environment and ambient noise surveys for compressor stations, liquefied natural gas facilities, meter and regulation facilities, and drilling locations.	9.3.1
Identify any state or local noise regulations applicable to construction and operation of the project.	9.3.3, 9.3.5
Indicate whether construction activities would occur over 24-hour periods.	9.3.2
Discuss construction noise impacts and quantify construction noise impacts from drilling, pile driving, dredging, etc.	9.3.2
Quantify operation noise from aboveground facilities, including blowdowns.	9.3.4
Describe the potential for the operation of the proposed facilities to result in an increase in perceptible vibration and how this would be prevented.	9.3.4.2.1.1

¹¹ Guidance Manual for Environmental Report Preparation, Volume I (FERC, 2017). Available online at: <https://www.ferc.gov/industries/gas/enviro/guidelines/guidance-manual-volume-1.pdf>.

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FILING REQUIREMENT	FOUND IN SECTION
Identify temporary and permanent noise sources that may have cumulative noise effects in addition to those resulting from the project.	9.3.4

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Resource Report No. 9 Agency Comments and Requests for Information Concerning Air and Noise Quality			
Agency	Date	Comment	Response/Resource Report Location
Bureau of Land Management (BLM)	9/26/2016	Not having an approved modeling protocol among the set of documents makes it difficult to assess modeling results. Having published modeling results, even interim results such as appear here, is most unconventional and contrary to concept of a modeling protocol. Several of them have a section "Model Selection". Firstly, this topic should be addressed in the associated modeling protocol. Secondly, in all cases, AERMOD is indicated as the model of choice without any discussion of the potential for complex winds (paragraph 7.2.8 in App. W of 40 CFR. Part 51). There is no justification for why AERMOD was chosen as opposed to (say) a non-steadystate puff model. Once this is properly done, the protocol should be appropriately cited in appropriate places within the modeling report. Another issue is that, as stated, the modeling results reported here are preliminary. The implication/understanding is that "final" results, which will presumably supersede these, will be issued at a future date. This will necessitate another review, which is counterproductive. I have not confirmed that all tabulated values reported link with respective appendices (e.g., App. C) that document their development. The term "data" is plural. There is inconsistency throughout the main report and its appendices: in some cases it's treaded as singular, in others, it (properly) treated as plural.	A modeling approach for all facilities, and preliminary modeling protocols for the Gas Treatment Plant (GTP) and Liquefaction Facility, were provided to agencies for review and comment. Additionally, several meetings with the Federal Energy Regulatory Commission (FERC) and interested agencies were held to discuss the modeling approach, protocols, and other details. Final modeling is consistent with the approach, protocols, and discussions. See Appendices D, E, and F.
BLM	9/26/2016	Put the report date on the cover page	Comment acknowledged.
BLM	9/26/2016	Fairly good spatial coverage. These monitoring stations operated by private entities and local, state, or federal agencies. Privately collected datasets are generally Prevention of Significant Deterioration (PSD) monitoring programs.	The text has been revised consistent with the comment.
BLM	9/26/2016	EPA, 2009a is an incorrect reference for the citation. Last 3 sentences of the 3rd paragraph: I don't see this in the tables!. There are seven available datasets on the North Slope, which provide a good representation of air quality. Air quality data being collected at this station includes CO, NO2, SO2, O3, PM10, and PM2.5. The proposed location of the second station is identified in Figure 9.2.2-2 as the preconstruction station ... This is NOT indicated in Fig. 9.2.2-2	There are multiple comments, and each is addressed sequentially and included in Section 9.2.2.2 and Appendix B. (1) The sentence has been revised to read "SPM data are not to be used for NAAQS compliance demonstrations without review and acceptance as required in 40 C.F.R. 58.20." with corrected citation. (2) The sentence is revised to state "Data collected at certain stations are above the level of the standards, which do not necessarily indicate exceedance of a standard." (3) The revised text has deleted "at North Slope oil and gas production facilities, as well as remote areas". (4) The data from the proposed location are not used in modeling compliance. The reference to use of data from the proposed location of the second station has

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			been removed, and the text is revised. The location is therefore not in Figure 9.2.2-2.
BLM	9/26/2016	The transient nature of fugitive emissions should be emphasized.	Section 9.2.3.1.1.3 is updated to state "Except for emissions from storage piles, fugitive emissions from construction activities are transient in nature and likely occur at any one location for short periods within a single day."
BLM	9/26/2016	caption: Total Annual Construction Emissions for the Liquefaction Facility and Marine Terminal	The caption has been revised.
BLM	9/26/2016	Combined PM10 emissions from all spreads peaks in Year 5.	This sentence is found in Section 9.2.3.3.1.1.
BLM	9/26/2016	1st full paragraph: as stated in general comments (above), the justification for use of AERMOD is not properly made. It should be properly made in the modeling protocol and then that document referenced here.	Justification for use of AERMOD is provided in Appendices D, E, and F.
BLM	9/26/2016	The statement above Table 9.2.5-2 is: "The model-predicted concentrations in Table 9.2.5-3 are below the respective increments." Yet in the table, 46.1 is not less than 30, and 15.6 is not less than 9.	To clarify the compliance demonstration, NAAQS/AAQS compliance is presented in a separate table from increment compliance. See Tables 9.2.5-3 and 9.2.5-4.
BLM	9/26/2016	"For modeling annual average impacts, the maximum modeled one- hour average concentrations were converted to annual averages using the scaling factor of 0.1." I don't see the relationship in table 9.2.5-7. Also in that table, there is nothing to compare the values to, so it's difficult for readers to get the context.	The revised data are in Table 9.2.5-16. Revised modeling was completed without the SCREEN approach, and therefore the modeling approach uses virtual meteorological data and used AERMOD at each site. NAAQS/AAQS values for comparison are provided at the bottom of Table 9.2.5-16.
BLM	9/26/2016	Table 9.2.5-9 is not referenced in the text.	The data are referenced and included as Table 9.2.5-20.
BLM	9/26/2016	Fugitive emissions of organic compounds,-would be emitted from piping components ...	The comma is removed from the revised text in in Section 9.2.5.2.3.
BLM	9/26/2016	A Pad meteorological data is considered representative ...	The text is revised to replace "is" with "are" in Section 9.2.5.2.3, paragraph 7.
BLM	9/26/2016	In Table 9.2.5-11, 57.3 is not less than 30.	To clarify the compliance demonstration, NAAQS/AAQS compliance is presented in a separate table from increment compliance. See Tables 9.2.5-22 and 9.2.5-23.
BLM	9/26/2016	In Table 9.2.5-12, the model-predicted value for 1-hr NO ₂ is very close to the standard.	Revised modeling shows that the one-hour nitrogen oxide (NO ₂) maximum impact is 158 ug/m ³ , which is less than 85 percent of the standard. The new data are

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			provided in Table 9.2.5-24.
BLM	9/26/2016	The air quality station location is shown in Figure 9.2.2-4 of Resource Report No. 9.	Appendix B has been revised to refer to Figure 9.2.2-2 of Resource Report No. 9.
BLM	9/26/2016	No particular comments. The document seems to be adequate and references are appropriate.	Comment acknowledged.
BLM	9/26/2016	Is the wind rose pattern more a result of diurnal or seasonal changes?	No analysis has been carried out to determine the diurnal/seasonal wind pattern (Appendix D, Figure 5-1), and such data would not be directly relevant to assessing impacts.
BLM	9/26/2016	While model results indicate NAAQS and AAAQS compliance for all pollutants and averaging periods, the following conservative assumptions should be noted:	Comment acknowledged.
BLM	9/26/2016	Since Sagwon CS appears to be close to the GTP (report doesn't say what the distance is), shouldn't its emissions be combined with those from GTP for modeling? Since Rabideux Creek CS appears to be close to the Liquefaction Facility (report doesn't say what the distance is), shouldn't its emissions be combined with those from the Liquefaction Facility for modeling?	As shown in Resource Report No. 9, Table 9.2.3-2, Sagwon Compressor Station is at milepost (MP) 75.97 (approximately 122 kilometers from the GTP). Rabideux Creek Compressor Station is at MP 675.23 (approximately 208 kilometers from the LNG Plant). Given the Compressor Station/Heater Station emissions and these distances, the impacts are not significant. See Appendix D, Section 4.2, for Liquefaction Facility offsite source screening and Appendix E, Section 4.2, for GTP offsite source screening.
BLM	9/26/2016	"Tables 3-1 and 3-2 show the proposed background ambient air concentrations and the ambient air monitoring station locations and periods of record for each compressor station location, respectively."	Appendix E, Section 4.0, is corrected to read "Tables 7 and 8 show the proposed background ambient air concentrations and periods of record for each modeled pollutant at each compressor station. See Resource Report No. 9, Figure 9.2.2-1, for ambient air monitoring station locations."
BLM	9/26/2016	It's not clear whether screening (via AERSCREEN) or refined modeling (via AERMOD) were used. In Section 5.7, where OLM is discussed, it appears that refined modeling was used.	In the final report, AERMOD is for refined modeling. Text regarding AERSCREEN has been removed. See Appendix E.
BLM	9/26/2016	"but outside of the AERMOD screening mode" ? This is confusing. AERMOD run in a screening mode? AERSCREEN is the screening tool. This entire section must be rewritten to clarify what is going on.	Appendix E, Sections 5.1 and 5.2, are updated to clarify use of AERMOD.
BLM	9/26/2016	EPA defines ambient air as that portion of the atmosphere, external to buildings, to which the general public has access (40 CFR 50).	Appendix E, Section 5.4.1 is updated consistent with 40 C.F.R. 50.1(e).

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BLM	9/26/2016	RE: Scenarios 1-3, is it really reasonable to assume that only 2 of 3 turbines would operate concurrently? This is not discussed in the text	Sagwon is designed with a backup turbine to operate during equipment malfunction or maintenance.
BLM	9/26/2016	There is a reference to App. G for "Detailed classified post maps illustrating the location of the maximum modeled pollutant impacts with respect to the modeled emission units" Yet the label for this appendix in the ToC of the manual report says "Non-Jurisdictional Facilities Air Quality Report (to be filed with FERC application)". This is a disconnect.	The text is corrected to reference Appendix G of this Appendix E.
BLM	9/26/2016	I suggest merging Tables 7 & 8 since they present the same information.	The tables represent the same information, but for different NAAQS. They are generated separately for clarity.
BLM	9/26/2016	Applicable Increments are shown in Table 2-1.	The table has been renumbered as Table 2-2.
BLM	9/26/2016	Are the NO2 concentrations weighted by WS class? The discussion and explanation as to how the background NO2 concentrations are derived is poorly explained. Readers should not have to review the 3 cited EPA documents in order to understand the methodology used in this analysis for the GTP.	The background hourly NO ₂ are sorted by wind speed category. Text is added in Appendix F to describe each of the references, and "Tiered approaches" including the Second Tier approach, under which backgrounds can vary by wind speed, direction, etc.
BLM	9/26/2016	Table 30-2 is not well documented or explained. It appears that a better caption for the table might be: 1-Hour NO2 Background Varying by Wind Speed For different concentration units, there are 2 series of values across WS classes. In Table 3-1, NO2 concentration values for volumetric and mass concentration are 32.8 and 61.7, resp. There is no explanation as to how the series of values in Table 3-2 yields the composite values reported in Table 3-1.	The text and table title in Appendix F are revised to clarify the data. The background one-hour NO ₂ in Table 3-1 is deleted and text was inserted to reference Table 3-2.
BLM	9/26/2016	The USEPA-approved American Meteorological Society/EPA Regulatory Model (AERMOD) modeling system was used assess ...	Appendix F text is corrected in Section 5.1.
BLM	9/26/2016	The processing of this data is provided ...	The text is corrected as requested, and is now in Section 5.3.1.
BLM	9/26/2016	In Table 4-1, I suggest translating the values into percent of data capture, not data loss.	Appendix F, Table 5-1 is revised to provide data recovery.
BLM	9/26/2016	Is the wind rose pattern more a result of diurnal or seasonal changes?	No analysis has been carried out to determine the diurnal/seasonal wind pattern (Appendix D, Figure 5-1), and such data would not be directly relevant to assessing impacts.
BLM	9/26/2016	Following recommendations provided by USEPA's AERMOD modeling contractor (Brode 2005) any reported	Appendix F, Section 5.3.4 is updated accordingly.

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		values ...	
BLM	9/26/2016	The grids were designed to accurately resolve the highest predicted pollutant impacts while at the same time minimizing model execution time. ... the Building Profile Input Program program also calculates the Good Engineering Practice (GEP) stack height.	The grammatical correction is made, now in the fourth paragraph of Section 5.4 and in Section 5.6.
BLM	9/26/2016	The last of Table 4-5 bleeds onto p. 29 only to present footnote d. In the final edition, I suggest reducing the bottom margin so that this footnote appears on the previous page (w/ the other three notes).	Appendix F "Modeled Source Physical Parameters" is now Table 4-4 and is reformatted accordingly.
BLM	9/26/2016	In Table 4-6, the same emission rates are listed for different averaging times. For example, in Row 1a, for SO ₂ , the same rate (1.245 g/s) appears for Annual and 1-hours. This same pattern appears many other places in the table with no explanation in the text for why this should be so. Also, how can a column be labeled both "3-hour" and "24-hour" ?	The data were intended to reflect the fact that the same instantaneous emission rate (g/sec) applies to all averaging periods for the model runs (1-hour, 3-hour, 24-hour, annual). In the revised modeling, now summarized in Table 4-3, the emission rates for the separate standards are revised to reflect different hourly and annual emission rates for the model input.
BLM	9/26/2016	The PVMRM2 option simulates the NO _x to NO ₂ conversion by calculating a ratio of the amount of O ₃ available to the amount of NO _x emitted into a plume at the downwind distance of a receptor from a source. To implement the PVMRM2 option, concurrent hourly ozone data is also required.	The text of Appendix F, Section 5.7, is updated accordingly.
BLM	9/26/2016	While model results indicate compliance with all applicable standards and thresholds, the following conservative assumptions should be noted:	The text of Appendix F, Section 7.1.2, is updated accordingly.
BLM	9/26/2016	In the list of acronyms, add "SOA" (= Secondary Organic Aerosol).	The text of Appendix F, Section 11.0, is updated accordingly.
BLM	9/26/2016	The lack of background sound scape data is evident throughout the proposed area of the project. Areas away from development nodes (per the BLM Utility Corridor Plan 1991) are of greatest concern for impacts from gas line project created sound. At present, the location of the compressor station at Tea Lake would in all likelihood create a constant sound scape impact on users in the Galbraith Lake area for many miles around.	Comment acknowledged. See Sections 9.3.1.1 and 9.3.1.3 for noise analysis approach for comparison of baseline noise and predicted noise level from Project facilities per FERC requirements.
BLM	9/26/2016	There are three permanent compressor station sites proposed that will affect BLM-managed lands near Galbraith Lake, Coldfoot, and the Ray River sites. The sites include clearing vegetation for 800-feet by 1200-feet, a 700-foot by 1000-foot gravel pad, multiple building (heights unknown), a 40-foot high communications tower, lights, fence, helipad, and access road. The current proposed sites are within 1000-feet of the highway and are expected to vent water vapor and emit a "humming sound" at approximately 55 dB during normal operations.	Comment acknowledged. See Section 9.3.1.3 and Appendix Q. Noise projections comply with the FERC criteria of a Day-Night Level (L _{dn}) of 55 dBA at the existing identified Noise-Sensitive Areas (NSAs). This is equivalent to a measured sound level of 48.6 dBA.
U.S. Environmental	9/30/2016	Please be advised that on August 1, 2016, CEQ issued the Final Guidance for Federal Departments and Agencies on	Final Council of Environmental Quality (CEQ) greenhouse gas

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Protection Agency (EPA)		Consideration of Greenhouse Gas Emissions and the Effects of Climate Change in NEPA Reviews. We expect that FERC will apply the guidance as the NEPA process for this project moves forward. The guidance document can be found here: https://www.whitehouse.gov/sites/whitehouse.gov/files/documents/nepa final ghg guidance.pdf . Greenhouse gas emissions include carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, nitrogen trifluoride, and sulfur hexafluoride, and should be expressed in metric tons of CO2-equivalent (mt CO2-e) per year.	(GHG) guidance has been removed from the White House website, so the status of the guidance is not clear. Nevertheless, Resource Report No. 9 provides estimates of direct GHG emissions. See Section 9.2.9.
EPA	9/30/2016	Consistent with the CEQ Guidance, the EPA recommends that the Reports estimate the direct and indirect GHG emissions caused by the proposal and its alternatives. We recommend that the GHG emissions quantification include an inventory of the air emissions units that were used to estimate the total GHG emissions from construction and operations. Examples of tools for estimating and quantifying GHG emissions can be found on CEQ's website. Direct GHG emissions that we recommend estimating in the Reports include: GHG emissions from mobile and stationary sources during all phases of project (e.g. construction, operations, maintenance, restoration); GHG emissions from project construction, operations and maintenance, and restoration. Indirect GHG emissions that we recommend estimating in the Reports include: Natural gas end use, GHG emissions from "Connected Actions," such as Kenai Spur Highway Relocation Project, and the PBU and PTU expansion projects, and Net GHG emissions and carbon stock changes of biogenic resources, such as wetlands, vegetation, permafrost, etc. Estimates of GHG emissions should be provided from project construction activities disturbing these biogenic resources and <u>resulting in the loss of stored carbon/GHG.</u>	Resource Report No. 9 was developed considering the CEQ GHG guidance. Final CEQ GHG guidance has been removed from the White House website, so the status of the guidance is not clear. Nevertheless, Resource Report No. 9 provides estimates of direct GHG emissions, including Non-Jurisdictional Facilities. See Section 9.2.9.
EPA	9/30/2016	Estimated GHG emissions levels can serve as a basis of comparison for climate change impacts among alternatives and appropriate mitigation measures. We recommend that the Reports identify reasonable GHG emission reduction targets or goals for some or all of the project components and development phases over the lifetime of the project. As the project develops, periodic reporting could demonstrate progress toward reaching these targets.	One of the Project design goals is to reduce GHG and other environmental impacts to the extent feasible. Thus, mitigation is already built into the Project.
EPA	9/30/2016	The Reports do not include consideration of future climate scenarios, and how they may impact the proposal, alternatives, and impacts. Consistent with the CEQ guidance, we recommend that the Reports describe potential changes to the affected environment that may result from climate change. Including future climate scenarios, such as those provided by the USGCRP's National Climate Assessment, in the Reports would help decision makers and the public consider whether the proposal includes appropriate resilience and preparedness measures for climate change. We recommend that the Reports include potential modifications, or descriptions of already incorporated modifications, to the design of the project to improve its resilience to the future climate scenarios. For example, the Reports indicate that	Resource Report No. 1, Sections 1.3 and 1.3.2.1.1 include consideration of future climate scenarios, including geothermal/permafrost issues, marine issues, and wildfire issues.

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		permafrost soils would be impacted. Permafrost stability or anticipated changes to existing permafrost conditions can affect settlement and ground stability characteristics that would in turn significantly influence design and construction of the project components, such as facilities and infrastructure.	
EPA	9/30/2016	We recommend that the Reports describe mitigation measures to avoid, reduce, or mitigate GHG emissions that are reasonable and consistent with achieving the purpose and need for the proposed Project. Such mitigation measures could include enhanced energy efficiency, lower GHG-emitting technology, carbon capture and sequestration, capturing or beneficially using GHG emissions, such as methane: a) In July 2015, the EPA launched the Natural Gas STAR Methane Challenge. This is a new voluntary program for reducing methane emissions. Methane, the primary component of natural gas, is a potent greenhouse gas with a global warming impact of 25 times that of carbon dioxide. Companies who sign up for the program agree to make commitments for methane emission reductions, with accountability and transparency in progress in achieving those commitments, and with the potential for public recognition for leadership in reducing GHG emissions in the United States. It may be appropriate to include consideration of the applicant enrolling in or employing measures described on the Gas STAR website (https://www.epa.gov/natural-gas-starprogram) in the Reports.	GHG emissions mitigation measures are described in Section 9.2.9.3 of Resource Report No. 9.
EPA	9/30/2016	b) Use of natural gas rather than diesel fuel would reduce GHG emissions. Natural gas and/or LNG powered heavy construction equipment, vehicles, power generators, dredges, barges, LNG carriers, etc. should be evaluated as a reasonable alternative to diesel power.	GHG emissions mitigation measures are described in Section 9.2.9.3 of Resource Report No. 9.
EPA	9/30/2016	c) The reclamation and revegetation of certain disturbed areas could reduce the overall project climate change impacts and result in the conversion of a carbon emission source to a carbon storage or sink. We recommend the Reports evaluate mitigating climate change impacts through reclamation and revegetation of disturbed project areas, including wetland enhancement or restoration, and potential conversion from a carbon source to a carbon sink and quantify the potential carbon sequestration from those actions.	The Applicant has considered the FERC Guidance Manual for Environmental Report Preparation and relevant guidance in the development of Resource Reports.
EPA	9/30/2016	d) We recommend that the Rep01 is describe in detail the proposed monitoring of GHG emissions and mitigation measures to ensure their effectiveness, including development of a GHG mitigation and monitoring plan. Adaptive management should be considered to evaluate whether there needs to be changes to the mitigation and monitoring plan.	The Applicant has considered the FERC Guidance Manual for Environmental Report Preparation and relevant guidance in the development of Resource Reports.
EPA	9/30/2016	We recommend including reference to the meteorology tables (9.2.1-3 to 9.2.1-7) for the climate zones of each facility.	See Sections 9.2.1.2 and 9.2.1.4 that include references to meteorological maps and tables

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			relevant to each facility.
EPA	9/30/2016	A meteorological monitoring station has been installed to supplement existing weather information in the vicinity of the Nikiski Liquefaction Facility. It is noted the Project representatives consulted and received approval from ADEC. We recommend providing footnotes or references outlining the correspondence related to these actions, including the quality assurance project plan (QAPP), if a QAPP was developed. Table 9.1.3-2 did provide reference to consultations regarding meteorological monitoring at the Deadhorse Gas Treatment Plant site, but not the Nikiski Liquefaction Facility. If the intention is to use the two monitoring station datasets for air quality modeling related to this or future projects, we recommend that the station be sited and operated in accordance with EPA Guidance provided in EPA-454/R-99-005. A Quality Assurance Project Plan (QAPP) should be developed and approved by ADEC and reviewed by the EPA. If a QAPP was developed in this case, please provide a reference to this document and related correspondence. Appendix B notes the Nikiski station is collecting air quality data and therefore assumed to be operating under a QAPP. We recommend including a reference to this document.	Section 9.2.1.3 includes a reference to Alaska Department of Environmental Conservation (ADEC) approval of monitoring methodology and the Quality Assurance Project Plan (QAPP).
EPA	9/30/2016	We recommend that this section be expanded to include wind-roses for a) the Nikiski LNG facility area, b) the Deadhorse GTP facility, and at least two other locations along the pipeline route. Wind-roses provide an effective method to illustrate wind climate at these locations.	Wind roses for the Nikiski LNG Plant, compressor stations along the pipeline route, and the GTP on the North Slope are provided in Appendices D, E, and F, respectively.
EPA	9/30/2016	We recommend removing the phrase "where water vapor becomes visible" To note, water vapor does not become "visible" at the dew point temperature (it is an invisible gas), but condenses into liquid form onto suspended particles, to form fog.	Section 9.2.1.4.5 has been revised per recommendation.
EPA	9/30/2016	We recommend including a reference to the QAPP for the ambient air quality station at the LNG site and the second site (the background ambient air monitoring station) if the QAPP is finalized.	A reference to the approved QAPP has been added to Section 9.2.2.2.
EPA	9/30/2016	A-PAD data were selected as representative of the North Slope site background for all criteria pollutants except PM (no PM monitor at A-PAD). CCP PM data selected as representative. A-PAD and CCP are the nearest monitoring sites to the Project GTP facility. CCP NO2 background values are much greater than A-PAD NO2 background values. We recommend some discussion be provided to justify why A-PAD data was selected as the more representative site for North Slope background values at the GTP site.	Detailed ambient air quality data summaries are provided in Appendix B. A Pad was chosen as the background site for GTP NO2 impact analysis because the Central Compression Plant (CCP) and Central Gas Facility are modeled as separate sources in the cumulative analysis. See Appendix F, Sections 4.2.1 and 7.3.2.
EPA	9/30/2016	Compressor Stations. Figure 9.2.2-7 depicts the location of approximately 11 compressor stations along the mainline pipeline and the location of PSD Class I and Sensitive Class II areas. We note that the Minto Compressor Station is in a remote location and may need additional new roads for access. We recommend that the Minto Compressor Station be collocated along the Elliott Highway near	Comment acknowledged. The current proposal is to install eight compressor stations at the locations depicted in Figure 9.2.2-7.

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		Livengood to avoid the need for additional new access roads.	
EPA	9/30/2016	Combustion emissions should include any sources associated with the transportation of cargo, fuel, personnel, etc. during construction of the Project. Transportation related emission sources should include marine barges/vessels, airplanes, railroad, passenger vehicle/trucks, etc. We recommend that the transportation related emissions be included in the emission estimates for the construction of the LNG Facility and Marine Terminal, Compressor and Heater Stations and Mainline Pipeline Spreads, PBTL and PBU Transmissions Line, and the GTP. We recommend including an inventory list of the number of air emissions units required for each facility used for project construction.	Construction emissions, including from combustion sources, are included in Appendix C.
EPA	9/30/2016	Table 9.2.3-2. We recommend that estimates of the GHG emissions (metric tonnes of CO ₂ -e/year) for the Compressor and Heater Stations be included as part of the mainline pipeline construction.	GHG emission estimates for construction and operation of compressor and heater stations are included in Tables 9.2.3-3 and 9.2.5-15.
EPA	9/30/2016	We recommend rewording the description for Minor Permits from "Owner or operator can establish permit limits to avoid compliance with specific regulations" to "Owner or operator can establish enforceable emission limits in a permit to avoid applicability of specific regulations."	Table 9.2.4-2 for 18 Alaska Administrative Code (AAC) 50.508 is reworded to be consistent with the comment.
EPA	9/30/2016	Combustion emissions should include any sources associated with the transportation of cargo, fuel, personnel, etc. during project operations. Transportation related emission sources should include marine barges/vessels, airplanes, railroad, passenger vehicle/trucks, etc. We recommend that transportation related emissions be included in the emission estimates for operation of the LNG Facility and Marine Terminal, LNG Carriers, Compressor and Heater Stations and Mainline Pipeline Spreads, PBTL and PBU Transmissions Line, and the GTP. We recommend including an inventory list of the number of air emissions units required for each facility used for project operations.	Emissions from operations, including from combustion sources, are included in Appendices D (Liquefaction Facility Air Quality Modeling Report), E (Main Pipeline Compressor Stations Air Quality Modeling Report), F (Gas Treatment Plant Air Quality Modeling Report), and G (Non-Jurisdictional Facilities Air Quality Report). Fine-grain details, such as number of air emissions units used during construction, can be found in the Appendices to these Appendices cited above, and available associated workbooks.
EPA	9/30/2016	We recommend that the project evaluate the feasibility of using natural gas powered LNG carriers to reduce diesel emissions. Our understanding is that the existing Kenai LNG facility in Nikiski has previously utilized natural gas powered LNG carriers.	Because the Applicant proposes to transport gas and transfer custody to LNG carriers (LNGCs) at the Marine Terminal, the Applicant would not have control over the type of propulsion systems to be used for LNGCs.
EPA	9/30/2016	We recommend including a reference for the draft modeling protocol. We recommend including a reference to isopleth figures that demonstrate the spatial distribution of maximum pollutant concentrations for each pollutant in the Appendix D modeling report. We recommend including isopleth figures in the Appendix D modeling report for the LNG facility. We recommend including the results of the	A modeling approach for all facilities, and preliminary modeling protocols for the GTP and Liquefaction Facility, were provided to agencies for review and comment. Additionally, several meetings with FERC and

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		Class I air quality and AQRV analysis as well as the secondary PM2.5 modeling analysis. We recommend including this analysis in the Appendix D modeling report also. The methodology for these modeling analyses were outlined in the LNG facility modeling protocol. Initial AQRV analysis was conducted and is included in version 2T of RR9 and associated appendices. Finalization of AQRV analysis should proceed in consultation with FERC and the Federal Land Managers (FLMs). We recommend including the qualitative ozone assessment discussed in the LNG facility modeling protocol.	interested agencies were held to discuss the modeling approach, protocols, and other details. Final modeling is consistent the approach, protocols, and discussions. See Appendices D, E, and F. Isopleths are not necessary to determine compliance, but they are included where available.
EPA	9/30/2016	We recommend including a reference to the compressor station modeling protocol.	See Appendix E related to modeling protocols.
EPA	9/30/2016	We recommend including a reference for the draft modeling protocol for the GTP facility. We recommend including a reference to isopleth figures that demonstrate the spatial distribution of maximum pollutant concentrations for each pollutant in the Appendix F modeling report. We recommend including isopleth figures in the Appendix F modeling report for the GTP facility. We recommend including the results of the Class I air quality and AQRV analysis as well as the secondary PM2.5 modeling analysis. We also recommend including the results of these analyses in the Appendix F modeling report. The methodology for these modeling analyses were outlined in the GTP facility modeling protocol. Initial AQRV analysis was conducted and is included in version 2T of RR9 and associated appendices. Finalization of AQRV analysis should proceed in consultation with FERC and the Federal Land Managers (FLMs) Qualitative analysis of ozone and PM2.5 is provided in RR9 draft 2T section 9.2.3.1.7, section 9.2.5.2.3 and associated appendices. We recommend including the qualitative ozone assessment discussed in the GTP facility modeling protocol. Such an analysis is included in section 9.2.5.2.3 of Draft 2T RR9.	See Appendix F related to modeling protocols.
EPA	9/30/2016	We encourage AK LNG and FERC to prepare a General Conformity Determination to address the Fairbanks non-attainment SIPs for both the construction and operations of the project as part of the public disclosure requirement under NEPA. During construction, pipe and cargo would be delivered to Fairbanks via the Alaska Rail Road and/or trucks along the major highways. Between Fairbanks and the North Slope, trucks would be transporting cargo and supplies via the existing highway system. Emissions from the railroad and trucks may represent a significant contribution of particulate matter.	See Section 9.2.6.10 and Appendix M.
EPA	9/30/2016	On August 1, 2016, Council on Environmental Quality issued final guidance on Consideration of Greenhouse Gas Emissions and the Effects of Climate Change in National Environmental Policy Act Reviews (Guidance). We expect that FERC will apply the guidance as the NEPA process for this project moves forward: https://www.whitehouse.gov/sites/whitehouse.gov/files/documents/nepa_final_ghg_guidance.pdf .Consistent with the CEQ Guidance, EPA recommends that Reports estimate the direct and indirect GHG emissions caused by the proposal and its alternatives. Examples of tools for	The Applicant has considered the <i>FERC Guidance Manual for Environmental Report Preparation</i> and relevant guidance in the development of Resource Reports. Resource Report No. 1, Sections 1.3 and 1.3.2.1.1) include consideration of future climate scenarios, including geothermal/permafrost issues, marine issues, and

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		estimating and quantifying GHG emissions can be found on CEQ's website. Direct GHG emissions that we recommend estimating in the Reports include: GHG emissions from mobile and stationary sources during all phases of project (e.g., construction, operations, maintenance, restoration); GHG emissions from project construction, operations and maintenance, and restoration, Indirect GHG emissions that we recommend estimating in the Reports include: Natural gas end use; <u>GHG emissions from "Connected Actions,"</u> such as the Kenai Spur Highway Relocation Project, and the PBU and PTU expansion projects; Net GHG emissions and carbon stock changes of biogenic resources, such as wetlands, vegetation, permafrost, etc. Estimates of GHG emissions should be provided from project construction activities disturbing these biogenic resources and resulting in the loss of stored carbon/GHG. GHG Emissions Targets - We recommend that the Reports identify reasonable <u>GHG emission reduction targets or goals</u> for some or all of the project components and development phases over the lifetime of the project. As the project develops, <u>periodic reporting</u> could demonstrate progress toward reaching these targets. The Reports do not include consideration of future climate scenarios, and how they may impact the proposal, alternatives, and impacts. Consistent with the CEQ guidance, we recommend that the Reports describe potential changes to the affected environment that may result from climate change. Including future climate scenarios, such as those provided by the USGCRP's National Climate Assessment, in the Reports would help decision makers and the public consider whether the proposal includes appropriate resilience and preparedness measures for climate change. We recommend that the Reports include potential modifications, or descriptions of already incorporated modifications, to the design of the project to improve its resilience to the future climate scenarios. For example, the Reports indicate that permafrost soils would be impacted. Permafrost stability or anticipated changes to existing permafrost conditions can affect settlement and ground stability characteristics that would in turn significantly influence design and construction of the project components, such as facilities and infrastructure. Including future climate scenarios can also provide context for the impacts of the proposal, and help inform whether the impacts may be exacerbated by climate change. We recommend FERC consider how the impacts of the proposal, including all alternatives, may be affected by future climate scenarios. If impacts of the proposal may be exacerbated by climate change,	wildfire issues. In regard to permafrost thaw, the chilling of the pipeline would help to mitigate future climate change and permafrost thaw; some thaw settlement is likely to occur, but the pipeline would be monitored, inspected, and maintained through in-line inspection and through a comprehensive field monitoring program over the life of the Project to ensure safe operation.
EPA	9/30/2016	We recommend that the GHG emissions quantification include an inventory of the air emissions units that were used to estimate the total GHG emissions from construction and operations.	See Appendices C, D, E, and F.
EPA	9/30/2016	GHG Mitigation Measures - We recommend that the Reports describe mitigation measures to avoid, reduce, or mitigate GHG emissions that are reasonable and consistent with achieving the purpose and need for the proposed Project. Such mitigation measures could include	The comment is noted. GHG emissions mitigation measures are described in Section 9.2.9.3 of Resource Report No. 9.

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		enhanced energy efficiency, lower GHG-emitting technology, carbon capture and sequestration, capturing or beneficially using GHG emissions, such as methane:	
EPA	9/30/2016	In July 2015, the EPA launched the Natural Gas STAR Methane Challenge. This is a new voluntary program for reducing methane emissions. Methane, the primary component of natural gas, is a potent greenhouse gas with a global warming impact of 25 times that of carbon dioxide. Companies who sign up for the program agree to make commitments for methane emission reductions, with accountability and transparency in progress in achieving those commitments, and with the potential for public recognition for leadership in reducing GHG emissions in the United States. It may be appropriate to include consideration of the applicant enrolling in or employing measures described on the Gas STAR website (https://www.epa.gov/natural-gas-star-program) in the Reports.	Comment acknowledged. The Applicant would monitor progress of this program for applicability to this Project.
EPA	9/30/2016	Use of natural gas rather than diesel fuel would reduce GHG emissions. Natural gas and/or LNG powered heavy construction equipment, vehicles, power generators, dredges, barges, LNG carriers, etc. should be evaluated as a reasonable alternative to diesel power.	GHG emissions mitigation measures are described in Section 9.2.9.3 of Resource Report No. 9.
EPA	9/30/2016	The reclamation and revegetation of certain disturbed areas could reduce the overall project climate change impacts and result in the conversion of a carbon emission source to a carbon storage or sink. We recommend the Reports evaluate mitigating climate change impacts through reclamation and revegetation of disturbed project areas, including wetland enhancement or restoration, and potential conversion from a carbon source to a carbon sink and quantify the potential carbon sequestration from those actions.	The Applicant has considered the <i>FERC Guidance Manual for Environmental Report Preparation</i> and relevant guidance in the development of Resource Reports.
EPA	9/30/2016	We recommend that the Reports describe in detail the proposed monitoring of GHG emissions and mitigation measures to ensure their effectiveness, including development of a GHG mitigation and monitoring plan. Adaptive management should be considered to evaluate whether there needs to be changes to the mitigation and monitoring plan.	The Applicant has considered the <i>FERC Guidance Manual for Environmental Report Preparation</i> and relevant guidance in the development of Resource Reports.
EPA	9/30/2016	Noise-Sensitive Areas (NSAs). The Reports should include additional noise receptors, such as cemeteries (during services); local, state, and national parks and preserves; federal wildlife refuges and state game refuges; designated critical habitat areas under ESA; etc.	See Sections 9.3.1.1 and 9.3.5 for the criteria used in selection and analyzing NSAs.
FERC	10/26/2016	The following commitments were made by AKLNG in resource report as information to be provided or pending in response to previous comments made FERC or other agencies. If the information will not be included in the application as indicated by AKLNG, provide a schedule for when it will be filed with FERC or provided to the requesting agency as applicable. <u>a. Qualitative discussion regarding the formation of secondary air pollutants (e.g., ozone, sulfates, and nitrates).</u>	Ozone and secondary particulate matter formation are discussed in Section 9.2.5.1.7 for the Liquefaction Facility and Section 9.2.5.2.3 for the GTP. For further details, see Appendices D and F.
FERC	10/26/2016	The following commitments were made by AKLNG in	See information included in

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		resource report as information to be provided or pending in response to previous comments made FERC or other agencies. If the information will not be included in the application as indicated by AKLNG, provide a schedule for when it will be filed with FERC or provided to the requesting agency as applicable. b. Chemical Accident Prevention Provisions applicability, specifically addressing the need for a risk management plan. (page 9-xii)	Section 9.2.6.8, and Appendix H.
FERC	10/26/2016	The following commitments were made by AKLNG in resource report as information to be provided or pending in response to previous comments made FERC or other agencies. If the information will not be included in the application as indicated by AKLNG, provide a schedule for when it will be filed with FERC or provided to the requesting agency as applicable. c. Permit applications and agency determinations. (page 9-xiii)	Sufficient data have been provided in Resource Report No. 9 to support the analysis of air quality impacts in the Environmental Impact Statement (EIS). The Applicant would be required to obtain air permits from ADEC prior to construction. A Prevention of Significant Deterioration (PSD) permit application would be provided to ADEC and copied to FERC during the development of the Draft EIS (DEIS).
FERC	10/26/2016	The following commitments were made by AKLNG in resource report as information to be provided or pending in response to previous comments made FERC or other agencies. If the information will not be included in the application as indicated by AKLNG, provide a schedule for when it will be filed with FERC or provided to the requesting agency as applicable. d. Monitoring results from the meteorological station installed on January 1, 2015 for the Liquefaction Facility. (section 9.2.1.3, page 9-11)	2015 monitoring results have been submitted to ADEC and have been approved. References to the 2015 monitoring results and approval have been included in Resource Report No. 9.
FERC	10/26/2016	The following commitments were made by AKLNG in resource report as information to be provided or pending in response to previous comments made FERC or other agencies. If the information will not be included in the application as indicated by AKLNG, provide a schedule for when it will be filed with FERC or provided to the requesting agency as applicable. e. Impact analysis for the Class I and Sensitive Class II Areas that have been identified to date. (section 9.2.2.3.4, page 9-31 and section 9.2.6.11, page 9-73)	Impacts at Class I and Sensitive Class II areas are included in Sections 9.2.5.1.5 and 9.2.1.6 for the Liquefaction Facility, in Section 9.2.5.2.1.3 for compressor stations, and in Section 9.2.5.2.3 for the GTP. For further details, see Appendices D, E, and F.
FERC	10/26/2016	The following commitments were made by AKLNG in resource report as information to be provided or pending in response to previous comments made FERC or other agencies. If the information will not be included in the application as indicated by AKLNG, provide a schedule for when it will be filed with FERC or provided to the requesting agency as applicable. f. Updated construction emission details as outlined in section 9.2.3. (section 9.2.3, page 9-34).	Section 9.2.3 provides updated construction emissions summaries. For further details, see Appendix C.
FERC	10/26/2016	The following commitments were made by AKLNG in resource report as information to be provided or pending in response to previous comments made FERC or other agencies. If the information will not be included in the application as indicated by AKLNG, provide a schedule for when it will be filed with FERC or provided to the	Open burning activity will depend on the construction contractors selected and cannot be provided at this time.

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		requesting agency as applicable. g. Open burning activity levels required for an estimate of combustion emissions of open burning of brush cleared from construction right-of-way. (section 9.2.3.1.1.1, page 9-35)	
FERC	10/26/2016	The following commitments were made by AKLNG in resource report as information to be provided or pending in response to previous comments made FERC or other agencies. If the information will not be included in the application as indicated by AKLNG, provide a schedule for when it will be filed with FERC or provided to the requesting agency as applicable. h. Non-combustion construction emissions, such as vented vapors from tanks. (section 9.2.3.1.1.2, page 9-35)	Non-combustion construction emissions are provided in Appendix C.
FERC	10/26/2016	The following commitments were made by AKLNG in resource report as information to be provided or pending in response to previous comments made FERC or other agencies. If the information will not be included in the application as indicated by AKLNG, provide a schedule for when it will be filed with FERC or provided to the requesting agency as applicable. i. Fugitive dust and particulate emissions from construction activities. (section 9.2.3.1.1.3, page 9-35)	Fugitive dust and particulate matter emissions from construction activities are provided in Appendix C.
FERC	10/26/2016	The following commitments were made by AKLNG in resource report as information to be provided or pending in response to previous comments made FERC or other agencies. If the information will not be included in the application as indicated by AKLNG, provide a schedule for when it will be filed with FERC or provided to the requesting agency as applicable. j. Liquefaction Facility vendor data and emissions estimates for equipment and operations based upon final design. In addition, provide the following operational emissions for the LNG Plant: i. startup and shutdown scenarios (including flare operations); ii. on-road vehicles; and iii. off-road support equipment. (section 9.2.5.1.1, page 9-47)	Vendors have not been selected and therefore vendor data are not available. However, vendor data are not necessary to estimate maximum project impacts. Maximum impacts are modeled and provided for each Project component. Emissions from startup flare operations, on-road vehicles, and off-road support equipment are estimated for the Liquefaction Facility and GTP and included in Appendices D and F. Emissions from routine startup/shutdown during long-term operations are a detail that is not yet addressed, but are expected to fit within the emissions envelope of the facilities. These data would be included in the final air permit applications, and provided at that time.
FERC	10/26/2016	The following commitments were made by AKLNG in resource report as information to be provided or pending in response to previous comments made FERC or other agencies. If the information will not be included in the application as indicated by AKLNG, provide a schedule for when it will be filed with FERC or provided to the requesting agency as applicable. k. Dispersion modeling results for the Jack River Heating Station. (section 9.2.5.2.1.2, page 9-56)	The Jack River Heater Station is no longer part of the Project design.
FERC	10/26/2016	The following commitments were made by AKLNG in	Estimates of fugitive GHG

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		resource report as information to be provided or pending in response to previous comments made FERC or other agencies. If the information will not be included in the application as indicated by AKLNG, provide a schedule for when it will be filed with FERC or provided to the requesting agency as applicable. l. Estimated annual fugitive greenhouse gas (GHG) emissions for the Mainline, PTTL, and the Prudhoe Bay Gas Transmission Line pipelines. (section 9.2.5.2.1.3, table 9.2.5-9, pages 9-56, 9-57)	(methane) emissions from pipelines are provided in Table 9.2.5-20.
FERC	10/26/2016	The following commitments were made by AKLNG in resource report as information to be provided or pending in response to previous comments made FERC or other agencies. If the information will not be included in the application as indicated by AKLNG, provide a schedule for when it will be filed with FERC or provided to the requesting agency as applicable. m. Gas Treatment Plant facility vendor data and emissions estimates for equipment and operations based upon final design. In addition, provide the following operational emissions for the GTP: i. startup and shutdown scenarios (including flare operations); ii. on-road vehicles, and iii. off-road support equipment. (section 9.2.5.2.3, page 9-59)	Vendors have not been selected and therefore vendor data are not available. However, vendor data are not necessary to estimate maximum project impacts. Maximum impacts are modeled and provided for each Project component. Emissions from startup flare operations, on-road vehicles, and off-road support equipment are estimated for the Liquefaction Facility and GTP and included in Appendices D and F. Emissions from routine startup/shutdown during long-term operations are a detail that is not yet addressed, but are expected to fit within the emissions envelope of the facilities. These data would be included in the final air permit applications, and provided at that time.
FERC	10/26/2016	The following commitments were made by AKLNG in resource report as information to be provided or pending in response to previous comments made FERC or other agencies. If the information will not be included in the application as indicated by AKLNG, provide a schedule for when it will be filed with FERC or provided to the requesting agency as applicable. n. determination whether minor New Source Review (NSR) permitting would be required for any construction sources. (sec 9.2.6.4, pg 9-70)	At this time, no New Source Review (NSR) permits have been identified for construction sources. A final determination would be made after construction contractors are selected.
FERC	10/26/2016	The following commitments were made by AKLNG in resource report as information to be provided or pending in response to previous comments made FERC or other agencies. If the information will not be included in the application as indicated by AKLNG, provide a schedule for when it will be filed with FERC or provided to the requesting agency as applicable. o. Final analysis of New Source Performance Standards, codified in 40 CFR, Part 60, based on final facility design of the planned Project facilities. (section 9.2.6.6, table 9.2.6-5, page 9-71)	Preliminary New Source Performance Standards (NSPS) (40 Code of Federal Regulations [C.F.R.] 60) determinations are provided in Section 9.2.6.6 and Appendix H. Final determinations would be made after construction contractors are selected.
FERC	10/26/2016	The following commitments were made by AKLNG in resource report as information to be provided or pending in	Preliminary NESHAPS (40 C.F.R. 61 and 63) determinations are

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		response to previous comments made FERC or other agencies. If the information will not be included in the application as indicated by AKLNG, provide a schedule for when it will be filed with FERC or provided to the requesting agency as applicable. p. Analysis of the applicability of National Emission Standards for Hazardous Air Pollutants, codified in 40 CFR, Part 61, based on final facility design. (section 9.2.6.7, pages 9-71 and 9-72; table 9.2.6-6, page 9-72)	provided in Section 9.2.6.7 and Appendix H. Final determinations would be made after construction contractors are selected.
FERC	10/26/2016	The following commitments were made by AKLNG in resource report as information to be provided or pending in response to previous comments made FERC or other agencies. If the information will not be included in the application as indicated by AKLNG, provide a schedule for when it will be filed with FERC or provided to the requesting agency as applicable. q. General Conformity analysis for areas the Project would affect, including emissions from mobile sources and where Project activities occur in the Fairbanks particulate matter less than 2.5 microns in aerodynamic diameter (PM _{2.5}) non-attainment area and applicable maintenance areas (section 9.2.6.9, page 9-73)	See Section 9.2.6.10 and Appendix M.
FERC	10/26/2016	The following commitments were made by AKLNG in resource report as information to be provided or pending in response to previous comments made FERC or other agencies. If the information will not be included in the application as indicated by AKLNG, provide a schedule for when it will be filed with FERC or provided to the requesting agency as applicable. r. Detailed Project plans describing mitigation measures that meet or exceed applicable regulations and standards, including the: i. Construction Emissions Control Plan (appendix I); ii. Fugitive Dust Control Plan (appendix J); and iii. Open Burning Plan (appendix K). (section 9.2.7, page 9-74)	Mitigation measures for construction, fugitive dust, and open burning would be developed in conjunction with contractor selection. These plans are outlined at this time to show the regulators what information would be provided once contractors are selected and construction planning completed.
FERC	10/26/2016	The following commitments were made by AKLNG in resource report as information to be provided or pending in response to previous comments made FERC or other agencies. If the information will not be included in the application as indicated by AKLNG, provide a schedule for when it will be filed with FERC or provided to the requesting agency as applicable. s. Operations emissions control plan (appendix L), including a description of emission control devices. (section 9.2.8, page 9-74)	Emission control devices would be determined as part of the Alaska Department of ADEC air permit Best Available Control Technology (BACT) process, and would be made available when permits are completed.
FERC	10/26/2016	The following commitments were made by AKLNG in resource report as information to be provided or pending in response to previous comments made FERC or other agencies. If the information will not be included in the application as indicated by AKLNG, provide a schedule for when it will be filed with FERC or provided to the requesting agency as applicable. t. Estimates of both construction and operational GHG emissions from jurisdictional and non-jurisdictional connected actions, including those identified in section 1.3.9 of Resource Report 1. (section 9.2.9.1.1.1, pages 9-62, 9-75, 9-76).	Estimates of emissions of GHGs from construction and operation of jurisdictional and non-jurisdictional facilities are provided in Section 9.2.9.1.
FERC	10/26/2016	The following commitments were made by AKLNG in	Emissions and impacts from

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		resource report as information to be provided or pending in response to previous comments made FERC or other agencies. If the information will not be included in the application as indicated by AKLNG, provide a schedule for when it will be filed with FERC or provided to the requesting agency as applicable. u. Associated operations accommodations camps (including dormitory emergency generator, communication tower generator, and three firewater pumps) in the GTP modeling analysis. (appendix F, section 4.7.1, page 25, and footnotes "d" and "e" of table 4-3)	operations camps are included in the GTP modeling analysis. See Appendix F.
FERC	10/26/2016	The following commitments were made by AKLNG in resource report as information to be provided or pending in response to previous comments made FERC or other agencies. If the information will not be included in the application as indicated by AKLNG, provide a schedule for when it will be filed with FERC or provided to the requesting agency as applicable. v. Modeling analysis that includes cumulative impacts from other sources. The exception is the planned Galbraith Lake compressor station located near the Alyeska Pipeline Service Company, Trans Alaska Pipeline System Pump Station 4. The next version of the modeling report for the compressor stations should include a modeling analysis for the Galbraith Lake station that would include the potential impacts from Pump Station 4 (appendix E, section 5.8, page 16)	Emissions and cumulative impacts from Pump Station 4 are included in the modeling results for Galbraith Compressor Station. See Appendix E.
FERC	10/26/2016	The following commitments were made by AKLNG in resource report as information to be provided or pending in response to previous comments made FERC or other agencies. If the information will not be included in the application as indicated by AKLNG, provide a schedule for when it will be filed with FERC or provided to the requesting agency as applicable. w. Baseline ambient sound survey for the planned Jack River Heater Station and Honolulu Creek Compressor Station and estimated noise impacts from facility operation at nearby noise sensitive areas (NSA), including, if necessary, planned mitigation measures to ensure that the noise attributable to the facilities would not exceed a day-night noise level of 55 A-weighted decibels (dBA) at any nearby NSA. (section 9.3.1.3.2, page 9-84)	The Jack River Heater Station is no longer part of pipeline design and the Honolulu Creek Compressor Station has moved such that the nearest NSA is greater than 1 mile away. With these changes, baseline survey and noise impact assessments are no longer relevant.
FERC	10/26/2016	The following commitments were made by AKLNG in resource report as information to be provided or pending in response to previous comments made FERC or other agencies. If the information will not be included in the application as indicated by AKLNG, provide a schedule for when it will be filed with FERC or provided to the requesting agency as applicable. x. Baseline ambient sound survey for the planned metering stations and mainline valves and estimated noise impacts from facility operation at nearby NSA, including, if necessary, planned	See Section 9.3.1.3.2.3 for noise analysis completed for metering stations and mainline valves. The baseline noise survey conducted for the for the Liquefaction Facility discussed in Section 9.3.1.2 included the associate meter station and Mainline block valve (MLBV) 30 given it is located at the facility.

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		mitigation measures to ensure that the noise attributable to the facilities would not exceed a day-night noise level of 55 dBA at any nearby NSA. (section 9.3.1.3.2.3, page 9-88)	The baseline surveys conducted for Galbraith Lake, Coldfoot, and Healy compressor stations included the associated MLBVs, located at each station. No baseline surveys were conducted at the remaining MLBVs and GTP meter stations. The requested information would be provided during DEIS development.
FERC	10/26/2016	The following commitments were made by AKLNG in resource report as information to be provided or pending in response to previous comments made FERC or other agencies. If the information will not be included in the application as indicated by AKLNG, provide a schedule for when it will be filed with FERC or provided to the requesting agency as applicable. y. Blasting plans for construction of the Project, including an analysis of noise and vibration impacts on affected NSAs. (section 9.3.2.1, page 9-88)	The Applicant will address this comment after the Final EIS (FEIS) but prior to construction start.
FERC	10/26/2016	The following commitments were made by AKLNG in resource report as information to be provided or pending in response to previous comments made FERC or other agencies. If the information will not be included in the application as indicated by AKLNG, provide a schedule for when it will be filed with FERC or provided to the requesting agency as applicable. z. Predicted sound levels for the Yukon River crossing as identified in table 9.3.2-2. (section 9.3.2-2, page 9-90)	See Section 9.3.2.2.1.1 and Appendix U.
FERC	10/26/2016	The following commitments were made by AKLNG in resource report as information to be provided or pending in response to previous comments made FERC or other agencies. If the information will not be included in the application as indicated by AKLNG, provide a schedule for when it will be filed with FERC or provided to the requesting agency as applicable. aa. Construction noise abatement plan including NSAs in the Project vicinity, predicted construction noise levels, and site-specific mitigation measures to be used to minimize construction noise impacts. (section 9.3.6, page 9-98)	See Appendix T Draft Template Construction Noise Abatement Plan. The Applicant will fully address this comment after the FEIS but prior to construction start.
FERC	10/26/2016	2. Construction activities for the Project have the following planned schedule for completion: LNG Plant: 8 years; Marine terminal: 2 years beginning Project year two; Mainline pipeline: 6 years; and the GTP: 9 years. These timelines do not represent short-term temporary Project construction emissions. Include modeling of these long-term construction impacts and confirmation of ADEC air quality permit exemptions for these construction activity emissions. (section 9.2.3, pages 9-34 to 9-37)	Impacts from construction emissions have not been included. Analysis of construction impacts consistent with ADEC requirements will be included in the air permit application.
FERC	10/26/2016	3. Include details on the permitting required for the construction camps. (section 9.2.3, pages 9-34 to 9-35)	See response to comment #89, Resource Report No. 9.
FERC	10/26/2016	4. Include a final list of both federal and state air quality regulations that would apply to the planned Project	A final list of both federal and state air quality regulations

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		construction activities. (section 9.2.4, tables 9.2.4-1 and 9.2.4-2, pages 9-41 to 9-45)	applicable to the Project is included in Section 9.2.4 and Appendix H (Project NSPS, NESHAPs, and RMP Applicability Analysis).
FERC	10/26/2016	5. Include the horsepower of each compressor. (section 9.2.5.1.1, page 9-53).	Heat input data (MMBtu/hour) as a surrogate for horsepower are provided in Appendix E.
FERC	10/26/2016	6. Include a final list of both federal and state air quality regulations that would apply to the planned Project operational activities for each applicable equipment type (e.g., gas turbines, emergency back-up engines, flares, fugitive emissions, etc.) (section 9.2.6.1, table 9.2.6-1, table 9.2.6-2, pages 9-63 to 9-67)	An updated list is provided in Section 9.2.6.
FERC	10/26/2016	7. Based on the information provided in section 9.2.5, both the LNG Plant and the GTP would be major sources subject to Prevention of Significant Deterioration review. Identify emission control technology or mitigation measures for criteria pollutants and GHGs, including any best available control technologies that would be implemented at these facilities to reduce emissions, along with details about control efficiency. (section 9.2.6.2, pages 9-67 to 9-69)	Emission control devices would be determined as part of the Alaska Department of ADEC air permit Best Available Control Technology (BACT) process, and would be made available when permits are completed.
FERC	10/26/2016	8. Update the Project General Conformity applicability analysis to include all direct and indirect Project emissions subject to General Conformity review. Direct emissions should include all direct construction emissions located in non- attainment or maintenance areas (vehicle traffic emissions, including worker commuting and equipment delivery; on- and off-road construction equipment emissions; fugitive dust and open burning emissions; and all operational emissions not permitted under a major or minor source NSR or Non-attainment NSR Permit), and all indirect emissions in non-attainment or maintenance areas, including additional passenger vehicle, truck, rail, barge, and air traffic emissions above existing load levels as identified in the current State Implementation Plan, induced by Project construction, and operation that would occur in a non- attainment or maintenance area. a. Direct and indirect emissions should be aggregated by non-attainment or maintenance area and calendar year for comparison to applicable General Conformity de minimis thresholds. b. If applicable General Conformity de minimis thresholds are exceeded for any calendar year(s), identify how the applicable Project emissions would conform with the State Implementation Plan for the applicable non- attainment or maintenance area and calendar year(s) using a method described in 40 CFR 93.158.	See Section 9.2.6.10 and Appendix M.
FERC	10/26/2016	9. Include a final list of federal regulations that would apply to Project marine vessel activities ranging from small service vessels to oceangoing vessels and detail how compliance with the regulations will be achieved (section 9.2.6.10, page 9-73)	A preliminary determination of applicable marine vessel regulations is provided Section 9.2.6.11. A final determination would be made after vessel contractors are selected.

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FERC	10/26/2016	10. states that the influence of Project GHG emissions on global climate change is not addressed in Resource Report 9. Per numerous agency and public comments, include a discussion of the Project's contribution to climate change in the Cumulative Impacts for the Project. As a guide for these cumulative impacts, reference the Southeast Market Pipelines Project, Final Environmental Impact Statement. Include discussion of the following climate change topics where applicable (Docket Nos. CP14-554-000, CP15-16-000, and CP15-17-000, FERC/EIS-0262F): a. sea-level rise; b. storm surge; c. flood events; and d. permafrost thaw, including incidental CO2 liberation.	The requested information will be provided during DEIS development
FERC	10/26/2016	11. Clarify whether receptors are required to be added in the offsite source boundaries for GTP modeling analysis	Receptors within the offsite sources are included in the modeling for GTP alone; however, receptors within offsite sources are not included in the cumulative modeling. See Appendix F Section 5.4, third paragraph.
FERC	10/26/2016	12. Update the summary of applicable ADEC and Alaska Administrative Code (AAC) 50 regulations to include revised standards that went into effect on August 20, 2016. (LNG Plant - appendix D, section 2.1 and table 2-1, page 9-10; GTP - appendix F, section 2.1 and table 2-1, page 7-8; Mainline Compressor Plants - appendix E, section 3.0 and table 2, page 8-9)	The summary has been updated based on the December 2016 regulations.
FERC	10/26/2016	13. Update footnote "c"/"1" of table to include limits for both nitrogen dioxide (NO2) (188 micrograms per cubic meter [µg/m3]) and PM2.5 (35 µg/m3) or refer to the standard generally. (LNG Plant - appendix D, section 2.1, table 2-1, page 10; GTP - appendix F, section 2.1, table 2-1, page 8; Mainline Compressor Plants - appendix E, section 3.0, table 2, page 9)	The values for PM _{2.5} and NO ₂ are included in the body of the tables.
FERC	10/26/2016	14 Include modeling input and output files to confirm that modeling described in report was completed as stated. Due to file size limitations on eLibrary, this information may need to be filed as text files. (LNG Plant - appendix D; GTP - appendix F; Mainline Compressor Plants - appendix E))	Electronic files for modeling will be made available.
FERC	10/26/2016	15. Include the background data that was used to develop the air quality data included in table 3-1. (appendix D, section 3.0, page 12)	See Appendix B.
FERC	10/26/2016	16. Include documentation for the emission factors used to calculate benzene annual emission rate. (appendix A of appendix D, page 13)	See Appendix D (specifically Appendix A of Appendix D, Section 8.2.).
FERC	10/26/2016	17. Update "Note 2" which is incomplete, referring to CO2. (appendix A of appendix D, page 14)	Appendix D has been revised and updated.
FERC	10/26/2016	18. Verify that AERMOD model version 15181 as discussed in appendix D was used for modeling and that the reference to model version 14134 in the text of the resource report is out of date. (section 9.2.5.1.3, page 9-49)	As documented in Appendix D, AERMOD version 15181 was used for modeling the LNG Plant. Section 9.2.5.1.4 has been updated accordingly.

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FERC	10/26/2016	19. Include consistent Ambient Background Concentration and Total Concentration (µg/m ³) for the 24-hour sulfur dioxide analysis in table 9.2.5-3 of Resource Report 9 and table 5.1 from appendix D. (section 9.2.5.1.3, pages 9-50; appendix D, section 5.5, page 33)	Table 9.2.5-3, Appendix B, and Appendix D are updated to be internally consistent.
FERC	10/26/2016	20. Update reference to ADEC's Modeling Review Procedures Manual (ADEC 2013), which has been updated as of May 16, 2016. (appendix F, section 1, page 4)	Appendix F is updated accordingly.
FERC	10/26/2016	21. Include BP Exploration (Alaska), Inc. (BPXA) A-Pad and Central Compression Plan (CPP) monitoring station data or reference in order to confirm background data used in modeling. (appendix F, section 3.0, page 10)	Documentation of sources for all ambient air quality data is provided in Appendix B.
FERC	10/26/2016	22. Particulate matter less than 2.5 microns in aerodynamic diameter background values included only 1 year of data (2014). Include the 98th percentile of the maximum daily averaged over a 3-year period. (appendix F, section 3.1, page 10)	See Appendix B.
FERC	10/26/2016	23. Include clarification of the use of AERMAP terrain pre-processors for the dispersion modeling. Section 9.2.5.2.3 describes AERMAP being used, but appendix F describes AERMAP as not being required due to flat terrain. (section 9.2.5.2.3, page 9-60; appendix F, section 4.4, page 19)	The reference to AERMAP has been deleted from the text in Section 9.2.5.2.3.
FERC	10/26/2016	24. In the air quality impact report, the description of the receptor grid should identify that the receptor locations are sufficient to cover employee housing. (page 9-xi)	Section 5.1 in Appendix E has been updated to indicate model versions.
FERC	10/26/2016	25. The modeling analysis reflects preliminary compressor station design parameters. Include a revised modeling analysis and report if the final design parameters (equipment, stack parameters, etc.) differ from the preliminary parameters. (appendix E, section 1.0, page 4)	Compressor station design parameters and air modeling analyses are updated for the latest project design information. See Appendix E.
FERC	10/26/2016	26. Update AERMOD, AERSCREEN, MAKEMET, and AERSURFACE modeling software to indicate updated versions of the modeling software were used. (appendix E, section 5.7, page 13)	See Appendix E, Section 5.1.
FERC	10/26/2016	27. Clarify how the nitrogen dioxide / nitrogen oxides ratio of 0.1 was derived from the ADEC data for application to the generators, heaters, and waste incinerators. (appendix E, section 5.7, page 16)	A reference to the source of the 0.1 in-stack ratio is included in the revised Appendix E, Section 5.7.
FERC	10/26/2016	28. In section 5.7, the text refers to table 3-2 which appears to be incorrect and suggest that it be revised to refer to table 4. (appendix E, section 5.7, page 16)	The text in Appendix has been revised accordingly.
FERC	10/26/2016	29. Ensure that all noise levels (background sound levels collected by Alaska LNG, noise estimates for construction and operational impacts) are provided in unweighted octave band centers and as A-weighted decibels. (section 9.3)	The background sound levels discussed in Section 9.3.1 and Appendices N and O are un-weighted octave band sound levels.
FERC	10/26/2016	30. Update the noise portion of Resource Report 9 to ensure that all noise related appendices are summarized within the text of the resource report. Include within the text of the resource report summaries of background noise data, construction and operational noise estimates, and mitigation measures proposed to be implemented for the	See Section 9.3 and various subsections for revised text and references that address this comment.

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FERC	10/26/2016	31. Include background noise estimates for all facilities identified in table 9.3.1-1 of Resource Report 9, regardless of the facility's proximity to NSAs. Include noise isopleths demonstrating noise impacts of the facility and distance attenuation until facility noise would be no longer perceptible (i.e., equal to or less than background noise estimates). (section 9.3.1, page 9-77)	See revised Section 9.3.1 and Table 9.3.1-1 for Project Facilities proximity to NSAs and Appendix N and O for background noise estimates. See Section 9.3.2 for predicted noise levels and impacts, and supporting modeling results in Appendices P through U. Noise isopleths demonstrating noise impacts of the facility and distance attenuation would require further quantification of the background sound at remote distances from facilities. The Applicant will address that requirement prior to the issuance of the DEIS.
FERC	10/26/2016	32. Revise the list of NSAs to include, as appropriate, Key Observation Points (KOP), as identified in Resource Report 8, any additional KOPs identified in comments on the draft resource reports, and subsistence use areas. For KOPs or subsistence use areas not included as an NSA, include justification for not considering the area as an NSA. Update noise impact assessments to demonstrate potential facility noise levels at the revised NSAs. (section 9.3.1.1, page 9-77)	See revised Section 9.3.1 and Table 9.3.1-1 for the NSAs analyzed and Section 9.3.2 for projected noise impacts on those NSAs. Further analysis related to Key Observation Points (KOPs) in Resource Report No. 8 will be addressed prior to the issuance of the DEIS. The Applicant requests clarification on definition of subsistence use areas to be considered for noise analysis.
FERC	10/26/2016	33. Include in the construction noise impact assessment potential noise impacts from construction activities on all NSAs. Identify proposed noise mitigation measures to limit noise impacts from construction activities on NSAs. (section 9.3.2, pages 9-88 to 9-91)	See Section 9.3.2 for predicted construction noise levels and impacts, and supporting modeling results in Appendices P through U for NSAs within 1 mile of Project facilities. The Applicant will further address this comment for other NSAs prior to the issuance of the DEIS.
FERC	10/26/2016	34. Include a detailed schedule showing all Project components where 24-hour construction activities are planned, including construction work camps. Include the season during which 24-hour construction activities would occur and the length of time that 24-hour construction activities would last. For major aboveground facilities (e.g., Liquefaction Facility, Marine Terminal, and GTP), also include the location within the site where the 24-hour activities would occur. (section 9.3.2, pages 9-88 to 9-91)	The Applicant will address this comment prior to the issuance of the DEIS.
FERC	10/26/2016	35. Estimate noise effects of increased vehicle traffic along the Dalton Highway and sensitive corridors of Highway 3 in proximity to Denali State Park and Denali National Park. (section 9.3.2, pages 9-88 to 9-91; section 9.3.4, pages 9-91 to 9-94)	The Applicant will address this comment prior to the issuance of the DEIS.
FERC	10/26/2016	36. Include noise impact analyses for the activities identified below: a. Construction and operational air traffic, including areas of Project-specific air traffic, estimated	The Applicant will address this comment prior to the issuance of

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		number of air trips per day during construction and facility operation in each air traffic area separated by vehicle type, estimated noise generated by air traffic based on vehicle type, and estimated noise impacts from air traffic at nearby NSAs. (section 9.3.2, page 9-88); b. On-land noise impacts from dredging and pile driving activities, including a map identifying all proposed areas of dredging and pile driving activities, the season and duration of pile driving activities, estimated noise generated by dredging and pile driving activities (peak sound levels and equivalent sound levels), and estimated noise impacts from dredging and pile driving activities at nearby NSAs. (sec9.3.2, page 9-88)	the DEIS.
FERC	10/26/2016	37. Include estimates of noise contributions attributable to Project construction and operation in lands managed by NPS and FWS located in proximity to Project. Estimates should include existing background noise levels, estimated noise levels attributable to Project construction and/or operation, season and duration of Project activities that would result in noise contributions to lands managed by NPS and FWS, and proposed mitigation measures to limit sound contribution from Project activities on NPS and FWS managed lands.(section 9.3.2, page 9-88)	The Applicant will address this comment prior to the issuance of the DEIS.
FERC	10/26/2016	38. Consult with NPS and FWS superintendents regarding noise contributions from Project activities in proximity to NPS and FWS managed lands during both construction and operation. Include documentation of the results of the consultations, including agreed upon mitigation measures.	Comment acknowledged. It is presumed that FERC will consult with the NPS and the USFWS during the FERC-led EIS process on these issues.
National Park Service (NPS)	9/26/2016	Much of the emissions information has not been compiled and was deferred until the FERC application, including emissions associated with construction (open burning, fugitive emissions, etc.). We cannot comment on the overall adequacy of the inventory until we have the entire inventory available.	Comment acknowledged.
NPS	9/26/2016	The analysis is incomplete because it did not include an assessment of air quality and AQRV impacts to Class I and sensitive Class II areas. The analysis was limited to air dispersion modeling results for NAAQS impacts using the near-field AERMOD model. Again, it does not include an AQRV assessment as requested by the NPS, nor does it include a far-field modeling assessment using CALPUFF or a PGM model. An FLM approved AQRV assessment needs to be included in the FERC application. Without this, direct effects to AQRVs cannot be discussed or evaluated in the NEPA document, nor can NPS comment on impacts in units of the National Park System or appropriate mitigation measures.	The report includes an assessment of Air Quality Related Values (AQRVs) and impacts at Class I and Sensitive Class II areas. CALPUFF is used for some assessments beyond 50 kilometers from the individual sources, for GTP and the Liquefaction Facility. Accepted EPA and ADEC protocols were used for determining which offsite sources to include in the cumulative impact modeling. Extensive details are provided in Appendices D, E, and F.
NPS	9/26/2016	Cumulative Impact - the analysis should evaluate the cumulative impact of all LNG connected sources (e.g., liquefaction facility, compressor stations and heater stations) within 300 km of the Denali National Park and Preserve (DNPP). In other words, the analysis needs to include a far-field modeling assessment that evaluates the 'direct effects' of the AK LNG facilities combined. The analysis should center on the Class I/sensitive Class II	Cumulative analyses are provided for Denali National Park and Preserve (DNPP) and other Class I and Sensitive Class II areas. See Appendices D, E, and F.

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		areas, and incorporate all LNG sources which are located within 300 km of given Class I/sensitive Class II area. This was not included in RR9 and needs to be included in the FERC application, as it is the only way to effectively evaluate the direct effects of all LNG facilities to AQRVs in Class I and sensitive Class II areas.	
NPS	9/26/2016	The analysis of compressor and heater station impacts only incorporates air dispersion modeling results for NAAQS impacts using the near-field AERMOD model - it does not include an AQRV assessment as requested by the NPS, nor does it include a far-field modeling assessment using CALPUFF or a PGM model. An FLM approved AQRV assessment needs to be included in the FERC application. A 'cumulative look' at all LNG facilities needs to be incorporated in the final application to effectively evaluate the direct effects to AQRVs in Class I and sensitive Class II areas.	Compressor station visibility impacts are provided for plume blight (contrast and color) using VISCREEN and for acid deposition using AERMOD. Using the Q/d methodology prescribed in FLAG, compressor stations are below the de minimus for regional haze analyses using CALPUFF. See Appendix E, Section 3.2.4.
NPS	9/26/2016	Regional Haze Rule discussion: The NPS will evaluate the final modeling results to ensure adverse effects to visibility do not occur as a result of the proposed project. However, as stated previously, we need an FLM-approved AQRV analysis, including visibility to be able to comment on the visibility impacts.	Visibility impacts are provided for plume blight (contrast and color) near compressor stations, and for regional haze impacts from the Liquefaction Facility and GTP. See Appendices D, E, and F.
NPS	9/26/2016	Natural and cultural sounds are integral components of the suite of resources and values that NPS managers are charged with preserving and restoring. NPS evaluates actions which may impact the human and natural environment within our parks with respect to our Organic Act mandates, including "...to conserve the scenery and the natural and historic objects and the wildlife therein and to provide for the enjoyment of the same in such a manner and by such means as will leave them unimpaired for the enjoyment of future generations." The "scenery," includes the natural soundscape, as well as the landscape (NPS Management Policies 2006). The NPS Director's Order #47 delegates to parks the responsibility to preserve natural soundscapes and eliminate or mitigate inappropriate noise sources. (NPS 2000). The NPS mission to preserve unimpaired the natural and cultural resources and values of the national park system results in a different perspective on "significant impacts" compared to that of the EPA and other agencies. In recognition of the differences in mission and acknowledgement that special consideration needs to be given to the evaluation of noise impacts on noise sensitive areas, it is imperative to provide information for the NPS to be able characterize the noise impacts from the proposed action. Only then can park managers make decisions about impacts to park resources, values and visitor experience. While the EPA's document 'Information on Levels of Environmental Noise Requisite to Protect Public Health and Welfare with an Adequate Margin of Safety' suggests a sound level of Ldn 55 dBA is appropriately protective for human health and welfare, NPS Management Policies 2006 §8.2.3 suggests an ecological paradigm for managing noise impacts, stating, "The natural ambient sound level—that is, the	Comment acknowledged. See revised Section 9.3.1 for additional details regarding noise analysis approach. Other than during construction for one season, there would be no noise signatures different than the vehicles, trains, and tourists that utilize the same corridor that would be utilized by the pipeline.

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		<u>environment of sound that exists in the absence of human-caused noise—is the baseline condition, and the standard against which current conditions in a soundscape will be measured and evaluated."</u> (NPS 2006b)	
NPS	9/25/2016	Data from a decade-long acoustic inventory project in Denali can be used to address a typical natural ambient sound level in the park. (Withers 2010, Withers 2011, Withers 2012, Withers and Betchkal 2013, Betchkal 2013a, Betchkal 2013b) Within the Denali vicinity the AK-LNG project spans a range of elevations from approximately 425 - 650 meters. During acoustic inventory sixteen summer-season sites were sampled within same elevation range. These sites have natural ambient levels ranging from 19.3 to 44.6 dBA, with a median of 26.3 dBA and a median absolute deviation of 3.2 dBA. Two winter monitoring sites in same elevation band had natural ambient levels of 20.1 and 21.2 dBA. Additionally, an Alaska-wide geospatial model of natural summer-season daytime sound levels (Mennitt 2013) can be used to estimate levels where empirical results do not exist. When considering areas within 3km of the pipeline route, the model suggests a median level of 29.8 dBA Leq(day) near Denali and a median level of 28.5 dBA Leq(day) near Gates of the Arctic. Both of these estimated ranges, empirically-derived 26.3 ± 3.2 dBA Leq(24), or model-derived 28.5 to 29.8 dBA Leq(day), are several orders of magnitude less energetic than 55 dBA Ldn or the corresponding equivalent level 48.6 dBA Leq(24), as referenced in §9.3.5.1. Managing noise impacts to this EPA human health and welfare threshold would allow an environment approximately 4 times as loud as a typical natural ambient level in Denali or Gates of the Arctic. Furthermore, impacts at 55 dBA Ldn / 48.6 dBA Leq(24) would reduce the listening area of humans and other animals in these environments by 99% or more. (Listening area reduction is calculated as follows: if N is an increase in background level measured in decibels, the fraction of the original listening area is given by $k = 10^{-N/10}$.) (Barber 2010, Box 2)	Comment acknowledged. The Applicant will further address this comment prior to the issuance of the DEIS.
NPS	9/25/2016	To better understand the impacts of the proposed project due to <u>noise</u> , the National Park Service requests the following information: 1) At the boundary of Denali National Park or Gates of the Arctic National Park and Preserve, please describe potential noise impacts from construction and operations phases of the project using a 20 dBA Leq(24) criterion. This threshold represents the approximate lower bound of observed natural acoustic conditions during summer months, and typical natural acoustic conditions in winter. For routing options that pass through park lands, please describe the approximate sound power level at the noise source. 2) Please clarify which, if any, standard methodologies (ISO, ANSI, etc) were employed when conducting acoustic field surveys and when performing propagation calculations. 3) Management of aviation noise in Denali NP&P and Gates of the Arctic NP&P is a well-developed concern addressed by Denali's Backcountry Management Plan (NPS 2006) and the Gates of the Arctic Wilderness Character Map (NPS 2016.) In addition, a number of best-practices have	Comment acknowledged. The Applicant will further address this comment prior to the issuance of the DEIS.

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		been developed to mitigate aviation noise impacts in Denali. (Denali Aircraft Overflight Advisory Committee 2012) Please describe aviation-related noise impacts that will occur due to routine patrols of the pipeline corridor, including the expected aircraft type, rate of patrol efforts, expected landings (if any), and the typical altitude above ground level at which these patrols will occur. For a portion of the proposed pipeline route, overflight noise footprints will affect Congressionally-designated Wilderness areas. Within designated Wilderness the Denali Backcountry Management Plan limits the maximum sound pressure level (Lmax) of motorized noise to 40 dBA Leq(1 second). If land-based mechanized patrols of pipeline corridor are expected to occur, describe the expected access vehicle(s), rate of patrol efforts, and any acoustic information necessary to describe compliance with Denali Backcountry Management Plan noise standards at Wilderness boundary. With these clarifications and additional analysis, NPS may better evaluate the environmental consequences of the proposed action to units of the national park system, and better support the conclusions reached in these Resource Reports.	
ADEC - Air Quality	9/25/2016	Table 9.2.2-1 The AAAQS value for ozone should be changed to 0.070 ppmv. This change was effective August 20, 2016.	The Applicant will address State of Alaska agency comments during the State permitting processes and timeframes.
ADEC - Air Quality	9/25/2016	Table 9.2.2-5 The Minor Source Baseline Date for the Southcentral Alaska Intrastate Air Quality Control Region for PM-2.5 should be changed to read " October 15, 2015"	The Applicant will address State of Alaska agency comments during the State permitting processes and timeframes.
ADEC - Air Quality	9/25/2016	The National Park Service and U.S. Fish and Wildlife Service have identified "sensitive Class II Areas" in the past, but we are not aware of Chugach National Forest making the same determination. Please provide details on when this determination has been made and by whom.	The Applicant will address State of Alaska agency comments during the State permitting processes and timeframes.
ADEC - Air Quality	9/25/2016	Paragraph two on this page mentions that a single hazardous air pollutant (HAP), formaldehyde will be emitted at a rate greater than 10 tons per year. It might be worthwhile to explain to the general public that formaldehyde is formed from the combustion of methane.	The Applicant will address State of Alaska agency comments during the State permitting processes and timeframes.
ADEC - Air Quality	9/25/2016	This paragraph notes that "the extent to which air quality, GHG emissions, and climate might be improved through this replacement cannot be quantified at this time." It should be noted that the Council on Environmental Quality (CEQ) released guidance on August 1, 2016 that sets a higher standard for the treatment of climate change and GHG emissions in NEPA documents. The current explanation may no longer be sufficient to meet the criteria found in the CEQ guidance.	The Applicant will address State of Alaska agency comments during the State permitting processes and timeframes.
ADEC - Air Quality	9/25/2016	Table 2-1 The AAAQS value for ozone should be changed to 0.070 ppmv. This change was effective August 20, 2016.	The Applicant will address State of Alaska agency comments during the State permitting processes and timeframes.
ADEC - Air Quality	9/25/2016	The final paragraph on this page notes that "ADEC has yet to revise the annual PM2.5 AAAQS to the same level as	The Applicant will address State of Alaska agency comments

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		the primary annual PM2.5 NAAQS promulgated in December 2012." This statement is incorrect, as the revision was effective as of March 2, 2016.	during the State permitting processes and timeframes.
ADEC - Air Quality	9/25/2016	Table 2 The AAAQS value for "particulate matter less than 2.5 Microns should be changed to 12 µg/m3. This revision was effective as of March 2, 2016. The NAAQS 8 hour value of 0.075ppmv is in error and should be changed to 0.070. The AAAQS value for ozone should be changed to 0.070 ppmv, as the revision was effective August 20, 2016.	The Applicant will address State of Alaska agency comments during the State permitting processes and timeframes.
ADEC - Air Quality	9/25/2016	The second bullet at the top of this page cites to the "Alaska Department of Environmental Conservation's (ADEC's) Modeling Review Procedures Manual (ADEC 2013)." This citation should be updated to refer to the 2016 version.	The Applicant will address State of Alaska agency comments during the State permitting processes and timeframes.
ADEC - Air Quality	9/25/2016	Table 2-1 The AAAQS value for ozone should be changed to 0.070 ppmv. This change was effective August 20, 2016.	The Applicant will address State of Alaska agency comments during the State permitting processes and timeframes.
ADEC - Air Quality	9/25/2016	The references on this page cite to the "Alaska Department of Environmental Conservation's (ADEC's) Modeling Review Procedures Manual (ADEC 2013)." This citation should be updated to refer to the 2016 version.	The Applicant will address State of Alaska agency comments during the State permitting processes and timeframes.
USFS	9/26/2016	1. We have reviewed emission inventory reported in Tables 9.2.5-1 and 9.2.5-2 to determine if an air quality modeling analysis for sensitive Class II area, the Chugach NF, would be necessitated by emissions from the proposed LNG Plant and Marine Terminal. Based upon the summation of emissions from these tables and the relative distance from the proposed LNG facility to the Chugach NF, the Q/d ratio exceeds the FLAG threshold of 10. When this threshold is exceeded, the affected FLM typically requests that a formal modeling analysis for air quality related values be conducted. We request an air quality modeling analysis be conducted for deposition focusing upon the Chugach NF.	An assessment of AQRV impacts at Chugach National Forest is provided in Tables 9.2.5-10 through 9.2.5-13. See also Appendix D.
USFS	9/26/2016	2. We requested development of an air quality modeling protocol in our July 30, 2015 letter regarding the Memorandum: Modeling Approach for Federal Conservation Unites (June 2015). However, no action has been taken upon this request as Resource Report 9 focuses exclusively upon near field modeling for NAAQS and PSD Class II increments. We again request development of an air quality modeling protocol, focusing upon application of the CALPUFF for deposition impacts. We would be happy to provide our guidance on the use of CALPUFF to assist in the development of a modeling protocol.	A modeling approach for all facilities, and preliminary modeling protocols for the Gas Treatment Plant (GTP) and Liquefaction Facility, were provided to agencies for review and comment. Additionally, several meetings with FERC and interested agencies were held to discuss the modeling approach, protocols, and other details. Final modeling is consistent with the approach, protocols, and discussions. See Appendices D, E, and F.

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ACRONYMS AND ABBREVIATIONS

Abbreviation	Definition
Abbreviations for Units of Measurement	
°F	degrees Fahrenheit
dBA	A-weighted decibels
L _{dn}	day-night sound level
L _{eq}	equivalent sound level
m ³	cubic meters
mg	Milligrams
mg/m ³	milligrams per cubic meter
MMBtu/hr	million British thermal units per hour
mph	miles per hour
ppb	parts per billion
ppbv	parts per billion by volume
ppm	parts per million
ppmv	parts per million by volume
psig	pounds per square inch gage
tpy	tons per year
µg	Microgram
µg/kg	micrograms per kilogram
µg/m ³	micrograms per cubic meter
Other Abbreviations	
§	section or paragraph
AAQs	Alaska Ambient Air Quality Standards
AAC	Alaska Administrative Code
ACRC	Alaska Climate Research Center
ADEC	Alaska Department of Environmental Conservation
ADOT&PF	Alaska Department of Transportation and Public Facilities
AGDC	Alaska Gasline Development Corporation
ANWR	Arctic National Wildlife Refuge
Applicant	The Alaska Gasline Development Corporation
AQ	air quality
AQCR	Air Quality Control Region
AQRV	Air Quality Related Value
ASOS	Automated Surface Observation System
AWOS	Automated Weather Observing System
BACT	Best Available Control Technology
BLM	United States Department of the Interior, Bureau of Land Management
BMP	best management practice
BOEM	United States Department of the Interior, Bureau of Ocean Energy Management
CEQ	Council on Environmental Quality

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Abbreviation	Definition
C.F.R.	Code of Federal Regulations
CAA	Clean Air Act
CASTNET	Clean Air Status and Trends Network
CCP	Central Compression Plant
CH ₄	methane
CO	carbon monoxide
CO ₂	carbon dioxide
CO ₂ e	total greenhouse gas emissions, in CO ₂ -equivalent global warming potential
COOP	National Weather Service, Cooperative Observer Program
CSN	Chemical Speciation Network
DAT	Deposition Analysis Threshold
DEIS	Draft Environmental Impact Statement
DGGS	Alaska Department of Natural Resources, Division of Geological & Geophysical Surveys
DNPP	Denali National Park and Preserve
ECA	Emission Control Act
EIAPP	Engine International Air Pollution Prevention
EIS	Environmental Impact Statement
EPA	United States Environmental Protection Agency
ERL	Environmental, Regulatory, and Lands
FAA	United States Department of Transportation, Federal Aviation Administration
FEIS	Final Environmental Impact Statement
FERC	United States Department of Energy, Federal Energy Regulatory Commission
FLAG	Federal Land Managers' Air Quality Related Values Work Group
FLM	Federal Land Manager
GHG	greenhouse gas
GIS	geographic information system
GTP	gas treatment plant
GWP	Global Warming Potential
H ₂ S	hydrogen sulfide
H ₂ SO ₄	sulfuric acid mist
HAP	hazardous air pollutant
HEA	Homer Electric Association
HDD	Horizontal Directional Drill
IMO	International Maritime Organization
IMPROVE	Interagency Monitoring of Protected Visual Environments
IPS	Initial Production System
ISO	International Organization for Standardization
KOP	Key Observation Point
Liquefaction Facility	natural gas liquefaction facility
LLC	limited liability company
LNG	liquefied natural gas

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Abbreviation	Definition
LNGC	liquefied natural gas carrier
MACT	maximum achievable control technology
Mainline	An approximately 807-mile-long, large-diameter gas pipeline
MARPOL	Marine Pollution Protocol
MGS	Major Gas Sales
MOF	marine offloading facility
MP	milepost
MSB	Matanuska-Susitna Borough
MW	Megawatt (10 ⁶ watts)
N ₂ O	nitrous oxide
NAAQS	National Ambient Air Quality Standards
NCDC	National Climatic Data Center
NCore	National Core Network
NEPA	National Environmental Policy Act
NESHAPs	National Emission Standards for Hazardous Air Pollutants
NGA	Natural Gas Act
NO ₂	nitrogen dioxide
NO _x	nitrogen oxides
NOAA	National Oceanographic and Atmospheric Administration
North Slope	Alaska North Slope
NPS	United States Department of the Interior, National Park Service
NSA	Noise-Sensitive Area
NSPS	New Source Performance Standards
NSR	New Source Review
NWR	National Wildlife Refuge
O ₂	oxygen
O ₃	ozone
Pb	the element lead
PBTL	Prudhoe Bay Gas Transmission Line
PBU	Prudhoe Bay Unit
PM _{2.5}	particulate matter having an aerodynamic diameter of 2.5 microns or less
PM ₁₀	particulate matter having an aerodynamic diameter of 10 microns or less
Project	Alaska LNG Project
PSD	Prevention of Significant Deterioration
PTTL	Point Thomson Gas Transmission Line
QAPP	Quality Assurance Project Plan
RICE	Reciprocating Internal Combustion Engine
SIP	State Implementation Plan
SLAMS	State and Local Air Monitoring Stations
SO ₂	sulfur dioxide
SOA	secondary organic aerosol

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Abbreviation	Definition
SPM	special purpose monitors
TBD	to be determined
U.S.	United States
USFS	United States Department of Agriculture, Forest Service
USFWS	United States Department of the Interior, Fish and Wildlife Service
VOC	volatile organic compound
WRCC	Western Regional Climate Center

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9.0 RESOURCE REPORT NO. 9 – AIR AND NOISE QUALITY

9.1 PROJECT DESCRIPTION

The Alaska Gasline Development Corporation (Applicant) plans to construct one integrated liquefied natural gas (LNG) Project (Project) with interdependent facilities for the purpose of liquefying supplies of natural gas from Alaska, in particular from the Point Thomson Unit (PTU) and Prudhoe Bay Unit (PBU) production fields on the Alaska North Slope (North Slope), for export in foreign commerce and for in-state deliveries of natural gas.

The Natural Gas Act (NGA), 15 U.S.C. § 717a(11) (2006), and Federal Energy Regulatory Commission (FERC) regulations, 18 Code of Federal Regulations (C.F.R.) § 153.2(d) (2014), define “LNG terminal” to include “all natural gas facilities located onshore or in State waters that are used to receive, unload, load, store, transport, gasify, liquefy, or process natural gas that is ... exported to a foreign country from the United States.” With respect to this Project, the “LNG Terminal” includes the following: a liquefaction facility (Liquefaction Facility) in Southcentral Alaska; an approximately 807-mile gas pipeline (Mainline); a gas treatment plant (GTP) within the PBU on the North Slope; an approximately 63-mile gas transmission line connecting the GTP to the PTU gas production facility (PTU Gas Transmission Line or PTTL); and an approximately 1-mile gas transmission line connecting the GTP to the PBU gas production facility (PBU Gas Transmission Line or PBTL). All of these facilities are essential to export natural gas in foreign commerce and will have a nominal design life of 30 years.

These components are shown in Resource Report No. 1, Figure 1.1-1, as well as the maps found in Appendices A and B of Resource Report No. 1. Their proposed basis for design is described as follows.

The new Liquefaction Facility would be constructed on the eastern shore of Cook Inlet just south of the existing Agrium fertilizer plant on the Kenai Peninsula, approximately 3 miles southwest of Nikiski and 8.5 miles north of Kenai. The Liquefaction Facility would include the structures, equipment, underlying access rights, and all other associated systems for final processing and liquefaction of natural gas, as well as storage and loading of LNG, including terminal facilities and auxiliary marine vessels used to support Marine Terminal operations (excluding LNG carriers [LNGCs]). The Liquefaction Facility would include three liquefaction trains combining to process up to approximately 20 million metric tons per annum (MMTPA) of LNG. Two 240,000-cubic-meter tanks would be constructed to store the LNG. The Liquefaction Facility would be capable of accommodating two LNGCs. The size of LNGCs that the Liquefaction Facility would accommodate would range between 125,000–216,000-cubic-meter vessels.

In addition to the Liquefaction Facility, the LNG Terminal would include the following interdependent facilities:

- **Mainline:** A new 42-inch-diameter natural gas pipeline approximately 807 miles in length would extend from the Liquefaction Facility to the GTP in the PBU, including the structures, equipment, and all other associated systems. The proposed design anticipates up to eight compressor stations; one standalone heater station, one heater station collocated with a compressor station, and six cooling stations associated with six of the compressor stations; four meter stations; 30 Mainline block valves (MLBVs); one pig launcher facility at the GTP meter station, one pig receiver facility at the Nikiski meter station, and combined pig launcher and receiver facilities at each of the compressor stations; and associated infrastructure facilities.

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Associated infrastructure facilities would include additional temporary workspace (ATWS), access roads, helipads, construction camps, pipe storage areas, material extraction sites, and material disposal sites.

Along the Mainline route, there would be at least five gas interconnection points to allow for future in-state deliveries of natural gas. The approximate locations of three of the gas interconnection points have been tentatively identified as follows: milepost (MP) 441 to serve Fairbanks, MP 763 to serve the Matanuska-Susitna Valley and Anchorage, and MP 807 to serve the Kenai Peninsula. The size and location of the other interconnection points are unknown at this time. None of the potential third-party facilities used to condition, if required, or move natural gas away from these gas interconnection points are part of the Project. Potential third-party facilities are addressed in the Cumulative Impacts analysis found in Appendix L of Resource Report No. 1;

- GTP: A new GTP and associated facilities in the PBU would receive natural gas from the PBU Gas Transmission Line and the PTU Gas Transmission Line. The GTP would treat/process the natural gas for delivery into the Mainline. There would be custody transfer, verification, and process metering between the GTP and PBU for fuel gas, propane makeup, and byproducts. All of these would be on the GTP or PBU pads;
- PBU Gas Transmission Line: A new 60-inch natural gas transmission line would extend approximately 1 mile from the outlet flange of the PBU gas production facility to the inlet flange of the GTP. The PBU Gas Transmission Line would include one-meter station on the GTP pad; and
- PTU Gas Transmission Line: A new 32-inch natural gas transmission line would extend approximately 63 miles from the outlet flange of the PTU gas production facility to the inlet flange of the GTP. The PTU Gas Transmission Line would include one-meter station on the GTP pad, four MLBVs, and pig launcher and receiver facilities—one each at the PTU and GTP pads.

Existing State of Alaska transportation infrastructure would be used during the construction of these new facilities including ports, airports, roads, railroads, and airstrips (potentially including previously abandoned airstrips). A preliminary assessment of potential new infrastructure and modifications or additions to these existing in-state facilities is provided in Resource Report No. 1, Appendix L. The Liquefaction Facility, Mainline, and GTP would require the construction of modules that may or may not take place at existing or new manufacturing facilities in the United States.

Resource Report No. 1, Appendix A, contains maps of the Project footprint. Appendices B and E of Resource Report No. 1 depict the footprint, plot plans of the aboveground facilities, and typical layout of aboveground facilities.

Outside the scope of the Project, but in support of or related to the Project, additional facilities or expansion/modification of existing facilities would be needed to be constructed. These other projects may include:

- Modifications/new facilities at the PTU (PTU Expansion project);

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- Modifications/new facilities at the PBU (PBU Major Gas Sales [MGS] project); and
- Relocation of the Kenai Spur Highway.

9.1.1 Purpose of Resource Report

As required by 18 Code of Federal Regulations (C.F.R.) § 380.12, this Resource Report has been prepared in support of a FERC application under Section 3 of the NGA to construct and operate the Project facilities. The purpose of this Resource Report is to:

- Describe the existing air quality and noise environment in the general vicinity of the Project;
- Summarize potential impacts to these resources resulting from construction and operation of the Project; and
- Identify appropriate mitigation measures to avoid or minimize potential adverse impacts to air quality and noise in the vicinity of the Project.

Appendices included in this Resource Report include the following:

- Appendix A Regional Climate Summaries for Meteorological Stations within the Project Vicinity;
- Appendix B Air Quality Monitoring Data within the Project Vicinity;
- Appendix C Emissions Associated with Project Construction;
- Appendix D Liquefaction Facility Quality Modeling Report;
- Appendix E Main Pipeline Compressor Stations Air Quality Modeling Report;
- Appendix F Gas Treatment Plant Air Quality Modeling Report;
- Appendix G Non-Jurisdictional Facilities Air Quality Report;
- Appendix H Project NSPS, NESHAPs, and RMP Applicability Analysis
- Appendix I *Construction Emissions Control Plan*;
- Appendix J *Fugitive Dust Control Plan*;
- Appendix K *Open Burning Plan*;
- Appendix L *Operations Emissions Management Plan*;
- Appendix M Air Conformity Report;
- Appendix N Baseline Noise Level Report – Liquefied Natural Gas (LNG) Facility;

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- Appendix O Baseline Noise Level Report – Mainline;
- Appendix P Liquefaction Facility Environmental Sound Level Assessment Report;
- Appendix Q Coldfoot Compressor Station Environmental Sound Level Assessment Report;
- Appendix R Healy Compressor Station Environmental Sound Level Assessment Report;
- Appendix S Horizontal Direction Drilling Environmental Sound Level Assessment Report; and
- Appendix T *Construction Noise Abatement Plan*.

The data for this Resource Report were compiled based on a review of the following:

- Feedback from FERC and other federal, state, and local agencies on Drafts 1 and 2 of the Environmental Report;
- Engineering design and proposed construction plans;
- Recent aerial photography;
- Meteorological and air quality data collected by Project representatives;
- Emissions modeling for the proposed facilities;
- Baseline noise surveys;
- Agency-supplied comments and data;
- Review of data from adjacent projects;
- Scientific literature; and
- Data from federal and state agencies.

9.1.2 Effect Determination Terminology

The following definitions were used when assessing the duration, significance, and outcome of potential effects related to the Project:

- **Duration:** *Temporary* effects are those that may occur only during a specific phase of the Project, such as during construction or installation activities. *Short-term effects* could continue up to five years. *Long-term* effects are those that would take more than five years to recover. *Permanent* effects could occur as a result of any activity that modified a resource to the extent that it would not return to preconstruction conditions during the 30-year life of the Project.
- **Significance:** *Minor* effects are those that may be perceptible but are of very low intensity and may be too small to measure. *Significant* effects are those that, in their context, and due to their intensity, have the potential to result in a substantial adverse change in the physical environment.
- **Outcome:** A *positive* effect may cause positive outcomes to the natural or human environment. In turn, an *adverse* effect may cause unfavorable or undesirable outcomes to the natural or human environment. *Direct effects* are “caused by the action and occur at the same time and place” (40 C.F.R. 1508.8). *Indirect effects* are “caused by an action and are later in time or farther removed

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in distance but are still reasonably foreseeable. Indirect impacts may include growth-inducing effects and other effects related to induced changes in the pattern of land use, population density, or growth rate, and related effects on air and water and other natural systems, including ecosystems” (40 C.F.R. 1508.8). Indirect impacts are caused by the Project, but do not occur at the same time or place as the direct impacts.

9.1.3 Agency and Organization Consultations

This section describes consultations that have been conducted with agencies and other interested parties related to the Project, as Project details are refined during preparation of Resource Report No. 9.

9.1.3.1 Federal Agencies

Discussions were held with several federal agencies regarding various Project details, including meetings and correspondence specific to air and noise quality, and those consultations are listed, along with a summary, in Table 9.1.3-1. A list of the required federal permits for the Project is provided in Resource Report No. 1, Appendix C. A summary of the agency, public, and stakeholder engagement is provided in Resource Report No. 1, Appendix D.

TABLE 9.1.3-1 Summary of Consultations with Federal Agencies (as of March 17, 2017)		
Contact	Date Contacted	Summary
Project Federal Land Managers (FLMs) Air Quality Meeting	April 21, 2015	Familiarize FLM agencies with the Project. Obtain feedback on the Project's proposed data sources for ambient air quality and meteorological data for impact assessment purposes. Request Air Quality Related Values (AQRVs) for Denali National Park and Preserve (DNPP) and Tuxedni National Wildlife Refuge (NWR). Identify any other FLM agency issues not already captured in the Project's plan to assess and manage AQRVs.
Letter from Debora Cooper (U.S. Department of the Interior, National Park Service [NPS]) to Norm Scott (Project)	June 8, 2015	Designation of sensitive Class II areas for the Project
Letter from Tamara McCandless (U.S. Department of the Interior, U.S. Fish and Wildlife Service [USFWS]) to Norm Scott (Project)	June 24, 2015	Response to request made during Federal Land Managers Air Quality Meeting on April 21, 2015
Letter from Karen Wuestenfeld (Project) to Brooke Merrell (NPS)	June 25, 2015	Project air quality modeling approach for Federal Conservation Units. Included Memorandum of Modeling Approach for Federal Conservation Units, Project, June 2015
Letter from Karen Wuestenfeld (Project) to Jewel Bennett (USFWS)	June 25, 2015	Project air quality modeling approach for Federal Conservation Units. Included Memorandum of Modeling Approach for Federal Conservation Units, Project, June 2015
Letter from Karen Wuestenfeld (Project) to Alan Peck, U.S. Department of the Interior, Bureau of Land Management (BLM)	June 25, 2015	Project air quality modeling approach for Federal Conservation Units. Included Memorandum of Modeling Approach for Federal Conservation Units, Project, June 2015
Letter from Karen Wuestenfeld (Project) to Deyna Kuntzsch U.S. Department of Agriculture, Forest Service (USFS)	June 25, 2015	Project air quality modeling approach for Federal Conservation Units. Included Memorandum of Modeling Approach for Federal Conservation Units, Project, June 2015

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TABLE 9.1.3-1 Summary of Consultations with Federal Agencies (as of March 17, 2017)		
Contact	Date Contacted	Summary
Letter from Earle Williams (BLM) to Karen Wuestenfeld (Project)	July 15, 2015	BLM comments on the Memorandum of Modeling Approach for Federal Conservation Units for the Project, dated June 2015
Letter from Joan Darnell (NPS) to Norm Scott (Project)	July 24, 2015	NPS comments on the Project's proposed Air Quality Modeling Approach.
Letter from Terri Marceron (USFS) to Karen Wuestenfeld (Project)	July 30, 2015	USFS Response to Modeling Approach for Federal Conservation Units, dated June 2015.
Letter from Karen Wuestenfeld (Project) to Herman Wong (U.S. Environmental Protection Agency [EPA])	July 31, 2015	Letter requested review of attached "Memorandum on Modeling Approach for Federal Conservation Units".
Project EPA Region 10 Air Quality Meeting	August 5, 2015	Familiarize EPA air quality staff with the Project. Obtain feedback on the Project's proposed data sources for ambient air quality and meteorological data for impact assessment purposes. Obtain feedback on the Project's proposed modeling approach. Identify other EPA air-related National Environmental Policy Act (NEPA) issues not already captured in the Project's plan.
Memorandum from Herman Wong (EPA) to Norm Scott (Project)	August 12, 2015	Letter responding to July 31, 2015, request and commenting on August 5, 2015 presentation
Email from Herman Wong (EPA) to Norm Scott (Project)	September 12, 2015	Weather research and forecasting solutions for the Project. Use of five-year simulation generated for the U.S. Department of the Interior, Bureau of Ocean Energy Management (BOEM) Alaska North Slope Study.
Letter from Karen Wuestenfeld (Project) to James Martin (FERC)	September 28, 2015	Response to FERC's May 15, 2015, request to the Project for information prior to submittal of the Draft 2 Resource Reports. Addresses comments 1a, 2a and 2b, and 3 in relation to Resource Report No. 9.
Project and FERC Air Quality Meeting	November 9, 2015	Obtain feedback from FERC on Project air modeling protocol, seeking general alignment with FERC prior to further agency engagement.
Project FLM Air Quality Meeting	April 26, 2016	Provide FLMs with project update and overview of draft modeling protocols for Liquefaction Facility and GTP. Obtain feedback from FLMs on overview of draft modeling protocols.
Project FLM Air Quality Meeting	June 30, 2016	Discuss protocols for conducting AQRV analyses for the liquefaction facility.

9.1.3.2 State Agencies

Discussions were held with several State of Alaska representatives regarding the Project details contained in this Resource Report, including meetings and correspondence specific to air and noise quality; those consultations are listed, along with a summary, in Table 9.1.3-2. A list of the required state permits for the Project is provided in Resource Report No. 1, Appendix C. A summary of the agency, public, and stakeholder engagement is provided in Resource Report No. 1, Appendix D.

TABLE 9.1.3-2 Summary of Consultations with Alaska State Agencies (as of March 17, 2017)		
Contact	Date Contacted	Summary

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TABLE 9.1.3-2 Summary of Consultations with Alaska State Agencies (as of March 17, 2017)		
Contact	Date Contacted	Summary
Project (Alaska Department of Environmental Conservation [ADEC]) Ambient Monitoring Presentation	February 18, 2014	Seek ADEC concurrence on ambient and meteorological monitoring approach—site locations and monitoring parameters. Discuss key requirements/issues related to the monitoring program. Discuss proposed monitoring schedule.
ADEC Air Quality Briefing	May 5, 2015	Familiarize ADEC with Project components, schedule, anticipated air permits, and contemplated sources of meteorological and ambient air quality data to support the air permit applications.
Letter from Karen Wuestenfeld (Project) to Alan Schuler (ADEC)	July 1, 2015	Letter requesting review of attached "Memorandum on Modeling Approach for Federal Conservation Units"
Letter from Alan Schuler (ADEC) to Karen Wuestenfeld (Project)	July 14, 2015	Letter responding to July 1, 2015 request
Letter from Charlie Kominas (Project/ExxonMobil) to Elizabeth Nakanishi (ADEC)	July 17, 2015	Meteorological Monitoring Site Approval Request, Gas Treatment Plant, Deadhorse, Alaska
Letter from Charlie Kominas (Project/ExxonMobil) to Elizabeth Nakanishi (ADEC)	October 14, 2015	Meteorological Monitoring Site Amendment Request, Gas Treatment Plant, Deadhorse, Alaska
Email from Elizabeth Nakanishi (ADEC) to Adrienne Rosecrans (Project/ExxonMobil)	October 28, 2015	Includes memo dated October 27, 2015, from Michael Gravier (ADEC) to Patrick Dunn, Response to Meteorological Monitoring Site Approval Request, Gas Treatment Plant, Deadhorse, Alaska
Project Fairbanks Metropolitan Area Transportation System (FMATS) Conference Call	June 6, 2016	Overview of the Project, transportation conformity, and general conformity.

9.2 METEOROLOGY AND AIR QUALITY

This section describes the meteorological conditions and existing air quality in the vicinity of the Project, as well as designated air quality management areas, such as Class I areas. This section also includes a description of the applicable air quality regulations, including requirements to submit site-specific permit applications for the proposed operations. Furthermore, this section provides estimates of Project impacts to air quality.

9.2.1 Regional Climate

Alaska's diverse climate is characterized by widely varying temperature ranges and weather phenomena due to the state's size, highly variable topographical features, and location within the high latitudes. The climate and meteorological conditions in localized areas of the Project will influence the design and operation of Project facilities. Meteorological conditions will also play an important role in determining (1) the direction of atmospheric transport and (2) the degree of dispersion of air pollutants emitted from emission sources associated with Project construction and operation.

9.2.1.1 Topographic Features and Elevation

Climate conditions are dramatically affected by topography and elevation, especially in Alaska where the influences of the Arctic Ocean and the Pacific Ocean are demarcated by major mountain ranges. The Brooks Range extends across northern Alaska and the Alaska Range extends across the southern third of

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Alaska, eastward into Canada. These two mountain ranges delineate the major climatic zones (see Section 9.2.1.2) that affect the Project, with smaller transitional areas between each of the zones.

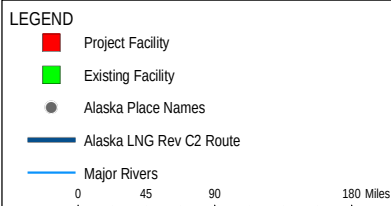
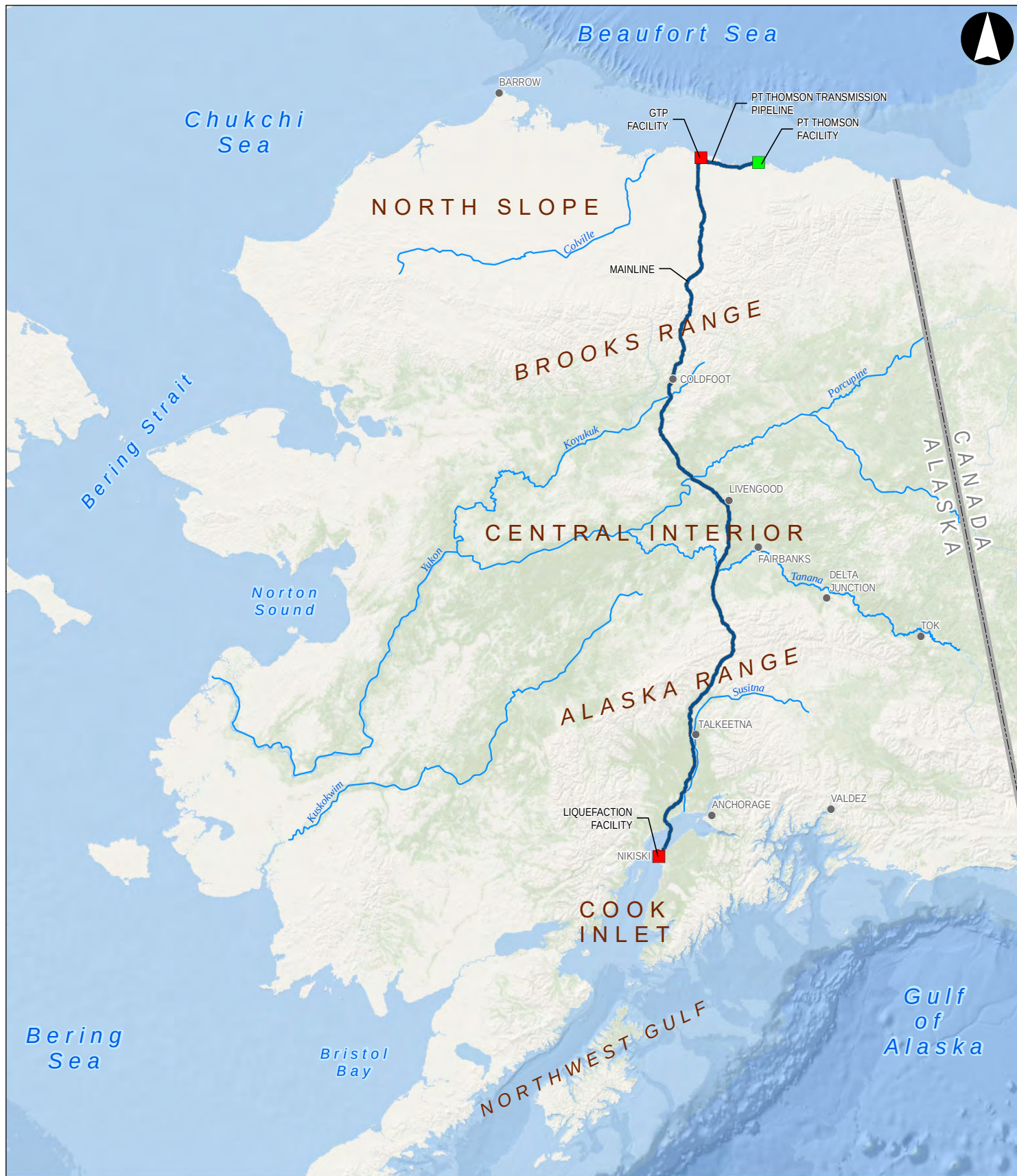
9.2.1.2 Climate and Regional Zones

The National Oceanic and Atmospheric Administration (NOAA) recently established 13 climate divisions for Alaska. Four of those divisions are relevant to the Project:

- North Slope;
- Central Interior;
- Cook Inlet; and
- Northwest Gulf.

The number of discrete climatic zones has sometimes been expanded to include two smaller, transitional alpine regions between the Central Interior and Cook Inlet zones (the Alaska Range) and between the North Slope and Central Interior zones (the Brooks Range). The climatic zones of Alaska relevant to this Project are depicted in Figure 9.2.1-1, and the applicable regions within these zones are as follows:

- North Slope – The North Slope region, north of the Brooks Range, is within the Beaufort Coastal Plain Ecoregion and is dominated by a traditionally described Arctic climate, with elevations ranging from sea level to approximately 1,500 feet in the Brooks Range foothills.
- Brooks Range – The Brooks Range, with elevations reaching 4,800 feet at Atigun Pass, is not a separate climatic zone; however, local elevation and topography, especially at locations in narrow valleys, leads to unique climate features in this region.
- Central Interior of Alaska – The Interior of Alaska, between the Brooks Range and the Alaska Range, is dominated by a traditionally described continental climate, with elevations ranging from a few hundred feet to approximately 1,000 feet.
- Alaska Range – The Alaska Range is not a separate climatic zone; however, local elevation and topography dominate the local climatic features. Elevations along the Project corridor range from approximately 1,000 feet in the foothills to 2,400 feet.
- Cook Inlet – The Southcentral portion of Alaska, south of the Alaska Range and including lands around Cook Inlet, is dominated by a traditionally described maritime climate, with a transitional zone in the southern foothills of the region. Elevations along the Project corridor range from approximately 1,000 feet in the Alaska Range foothills to sea level along Cook Inlet.
- Northwest Gulf – The climate conditions in and around Kodiak Island and over the open waterbodies, including Shelikof Strait and the Kennedy Entrance to Cook Inlet, represent climate conditions for LNG carriers (LNGCs) entering and exiting Cook Inlet for access to the Marine Terminal.



DISCLAIMER

The information contained herein is for informational or planning purposes only. It does not nor should it be deemed to be an offer, request or proposals for rights or occupation of any kind. The Alaska LNG Project Participants and their respective officers, employees and agents, make no warranty, implied or otherwise, nor accept any liability, as to the accuracy or completeness of the information contained in these documents, drawings or electronic files. Do not remove or delete this note from document, drawing or electronic file.

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APPLICABLE CLIMATE ZONES AND TOPOGRAPHY OF ALASKA

FIGURE 9.2.1-1

ALASKA LNG

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Descriptions of meteorological conditions in the vicinity of Project² components follow. Summary climatic statistics are provided in the next section.

9.2.1.2.1 Liquefaction Facility

At the proposed location of the Liquefaction Facility on Cook Inlet, a maritime climate prevails. The maritime climate is influenced by exposure to the Gulf of Alaska and is wetter and, overall, warmer than the climate in the rest of the Project area. Frequent precipitation occurs in all months, with average precipitation above 3 inches in July and a seasonal peak in the fall. Snowfall occurs in winter months, with an average snow depth of 1 foot in January and February, along with cloudiness and comparatively milder temperatures than the other regions of the Project. Summer daily maximum temperatures average slightly above 60 degrees Fahrenheit (°F) and winter average daily minimum temperatures are below 10 °F. LNGCs would transit Cook Inlet from the Marine Terminal at Nikiski 115 nautical miles south to Kennedy Entrance, which is the recommended passage to and from Cook Inlet. It is also possible to use Stevenson Entrance (125 nautical miles south of the Marine Terminal) or Shelikof Strait Entrance (235 nautical miles south of the Marine Terminal). As the LNGCs approach the Gulf, the climate becomes increasingly mild and wet.

9.2.1.2.2 Interdependent Project Facilities

In addition to the Liquefaction Facility, Project facilities would include the Mainline, GTP, PBTL, and PTTL to move and process natural gas from the North Slope to the Liquefaction Facility. On the North Slope, the Project facilities, including Mainline, GTP, PBTL, and PTTL, would be exposed to cold Arctic weather and associated windflow patterns. The Arctic climate is characterized by very cold winters, persistent high wind episodes (any season), and frequent fog conditions that are influenced by windflow from the ice shield, especially in the warmer months.

For the Mainline components in the Alaska Interior, there are very cold, stable air episodes in the winter with a warmer growing season in the summer. Occasional periods of high temperature, dry conditions, and stable atmospheric conditions occur in the summer.

The Mainline corridor will cross mountain range transition zones, which generally involve cold winter conditions, an abundance of precipitation (mainly snow), and rapidly changing weather. Local climatic conditions are heavily influenced by local topographic features in these mountainous regions.

In Southcentral Alaska, the southernmost portion of the Mainline corridor, a maritime climate similar to the one described for the Liquefaction Facility prevails.

In subsequent sections of this Resource Report, climatological and air quality data are provided for the Project area, including data from some stations that are representative of the Brooks and Alaska Ranges.

² The terms “Project area” and “Project footprint” are defined to include the Project facilities and land requirements for construction and operation. The term “Project vicinity” is used to mean the region near or surrounding the Project area and draws its meaning from the context in which the term is used.

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9.2.1.2.3 Non-jurisdictional Facilities

As outlined in Resource Report No. 1, there are three categories of non-jurisdictional facilities, discussed in more detail in the following sections, that warrant environmental analysis as connected actions: (i) the PTU Expansion project; (ii) the PBU MGS project; and (iii) the Kenai Spur Highway relocation project.

The PTU Expansion project and PBU MGS project located on the North Slope would be subject to similar North Slope climatic conditions as the existing Point Thomson project and GTP, respectively.

The Kenai Spur Highway relocation project would be subject to Cook Inlet climatic conditions similar to those at the Liquefaction Facility.

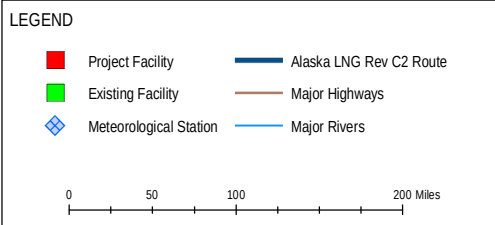
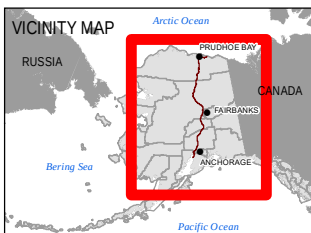
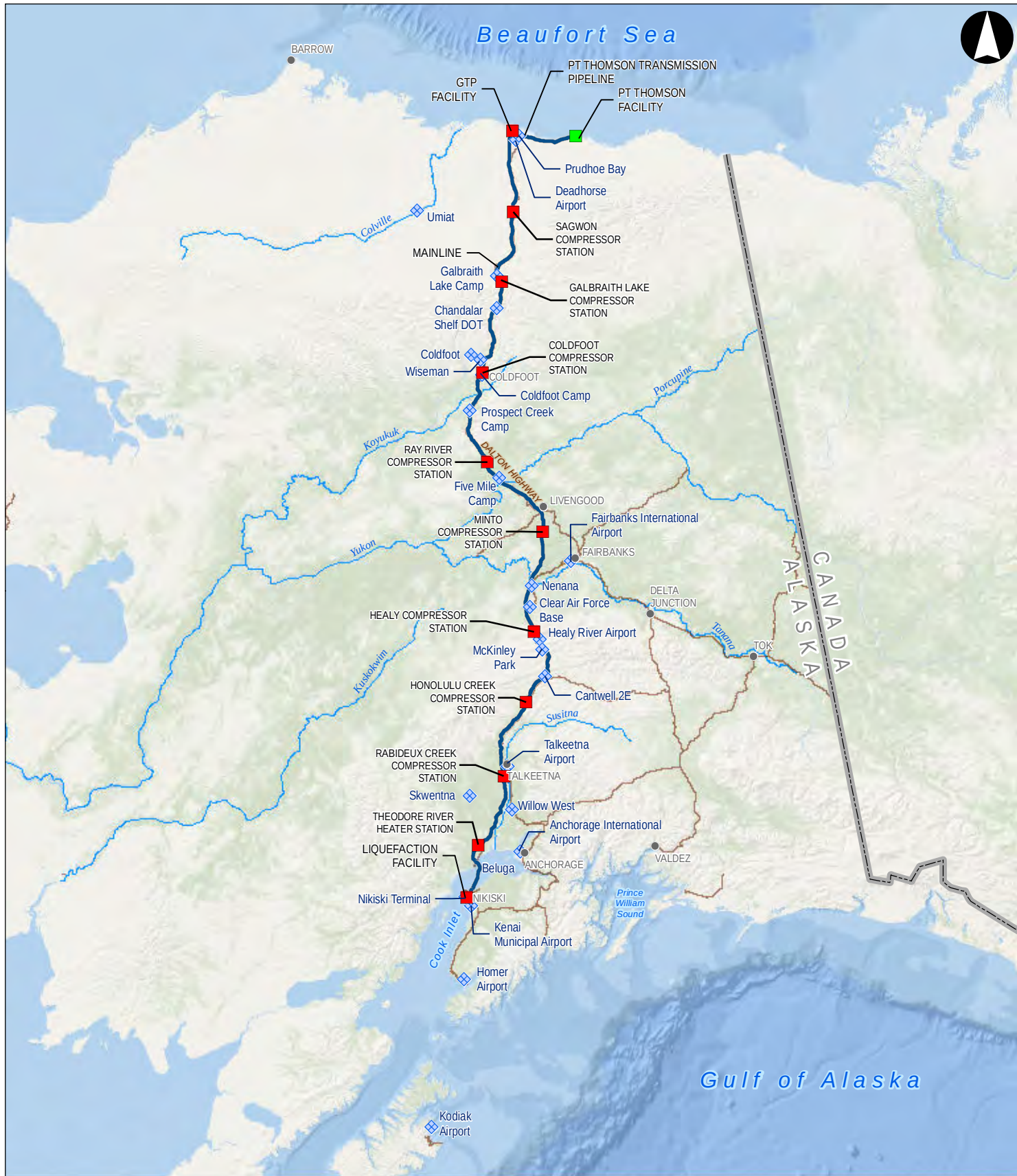
9.2.1.3 Meteorological Stations

A number of existing weather stations are maintained in the Project vicinity and provide data useful for characterizing weather conditions that would exist during Project construction and operation. Table 9.2.1-1 lists the stations that have been identified in the Project vicinity and Figure 9.2.1-2 depicts their location. Information from these stations has been obtained from several climate agencies, including the National Climatic Data Center (NCDC), Alaska Climate Research Center (ACRC), and Western Regional Climate Center (WRCC). Detailed monthly climate statistics from a number of stations within the general Project vicinity are presented in Appendix A, and average monthly data for the designated groups (Liquefaction Facility, North Slope, Brooks Range, Central Interior of Alaska, Alaska Range, Cook Inlet, and the Northwest Gulf) are shown Figures 9.2.1-3 through 9.2.1-7. Although the Liquefaction Facility is not located in a separate climate division, data are provided separately given the potential sensitivity of LNG terminal operations to ongoing weather. The Northwest Gulf division climate conditions would be representative of LNGC operations entering Cook Inlet through the Shelikof Strait and the Stevenson and Kennedy Entrances to Cook Inlet. A meteorological monitoring station was installed and operated to supplement existing weather station information in the vicinity of the Liquefaction Facility. That monitoring was initiated on January 1, 2015. The station location is shown in Figure 9.2.2-2. Prior to choosing this monitoring site and the meteorological parameters, the Project representatives consulted with and received approval from ADEC (Alaska LNG Project, 2015), including the Quality Assurance Project Plan (QAPP). The results of that monitoring effort for 2015 are summarized in an annual data report that has been approved by ADEC (Alaska LNG Project, 2016).

TABLE 9.2.1-1 Description of Meteorological Measurement Stations within the Project Vicinity						
Station Name	Station Type	Data Record Summarized	North Latitude	West Longitude	Elevation (feet)	Information Source
LIQUEFACTION FACILITY						
Nikiski Terminal	COOP	1967–1978	60.66667	-151.38333	110	NCDC
Kenai FAA Airport	Airways, ASOS, COOP	1949–2012	60.56667	-151.25	91	NCDC
Interdependent Project Facilities						
NORTH SLOPE						
Prudhoe Bay	COOP	1986–1999	70.25	-148.3333	50	WRCC
Deadhorse	Airways, ASOS, COOP	1999–2010	70.1917	-148.4772	61	ACRC/NCDC

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TABLE 9.2.1-1 Description of Meteorological Measurement Stations within the Project Vicinity						
Station Name	Station Type	Data Record Summarized	North Latitude	West Longitude	Elevation (feet)	Information Source
Umiat	COOP	1949–2001	69.36944	-152.14	266	NCDC
BROOKS RANGE						
Galbraith Lake	COOP	1970–1980	68.47889	-149.49	2,666	WRCC
Chandalar ADOT&PF	COOP	2000–2010	68.0781	-149.5647	3,250	NCDC
Wiseman	COOP	1949–2010	67.4192	-150.1069	1,147	WRCC
Coldfoot Camp	COOP	1970–1977	67.2667	-150.2333	1,102	WRCC
CENTRAL INTERIOR						
Bettles Airport	Airways, ASOS, COOP	1951–2010	66.92	-151.52	643	ACRC/NCDC
Prospect Creek Camp	Airways, COOP	1970–2001	66.82361	-150.66889	955	NCDC
Five Mile Camp	COOP	1970–1980	65.9333	-149.8333	440	WRCC
Fairbanks International Airport	ASOS, COOP	1949–2010	64.8039	-147.8761	432	ACRC/NCDC
Nenana Municipal Airport	ASOS	1949–2001	64.55	-149.07167	360	NCDC
Clear Air Force Base	COOP	1965–1997	64.3	-149.18333	580	NCDC
ALASKA RANGE						
Healy River Airport	Airways, AWOS	1976–2012	63.86611	-148.96889	1,294	NCDC
McKinley Park	AWOS	1949–2012	63.73333	-148.91667	1,720	NCDC
Cantwell 2E	COOP	1983–2011	63.3952	-148.895	2,132	NCDC
COOK INLET						
Talkeetna Airport	ASOS, COOP	1949–2012	62.32	-150.095	350	NCDC
Willow West	COOP	1960–2011	61.748	-150.0541	205	NCDC
Skwentna	COOP	1949–2012	61.9772	-151.2169	150	NCDC
Anchorage International Airport	Airways, ASOS, COOP	1931–2012	61.169	-150.0278	120	NCDC
Beluga	COOP	1973–1992	61.18333	-151.03333	79	NCDC
Homer Airport	ASOS, COOP	1932–2012	59.642	-151.4908	64	NCDC
NORTHWEST GULF						
Kodiak Airport	ASOS, COOP	1973-2012	57.75111	-152.48556	72	NCDC
Sources: NCDC, National Climate Data Center, http://www.ncdc.noaa.gov/oa/climate WRCC, Western Regional Climate Center, http://www.wrcc.dri.edu/summary/Climsmak.html Abbreviations: Airways: Airport FAA – Federal Aviation Administration ASOS – Automated Surface Observation System COOP – National Weather Service Cooperative Observer Program ADOT&PF – Alaska Department of Transportation and Public Facilities AWOS – Automated Weather Observing System NCDC – National Climatic Data Center WRCC – Western Regional Climate Center ACRC – Alaska Climate Research Center						



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METEOROLOGICAL STATIONS WITHIN THE PROJECT VICINITY

FIGURE 9.2.1-2

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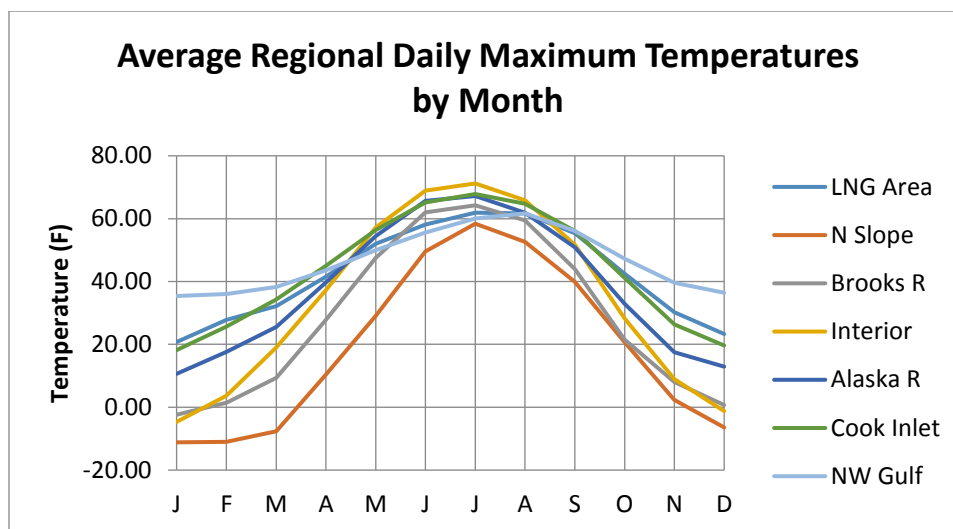


FIGURE 9.2.1-3 Average Regional Daily Maximum Temperatures by Month

Sources: See Appendix A

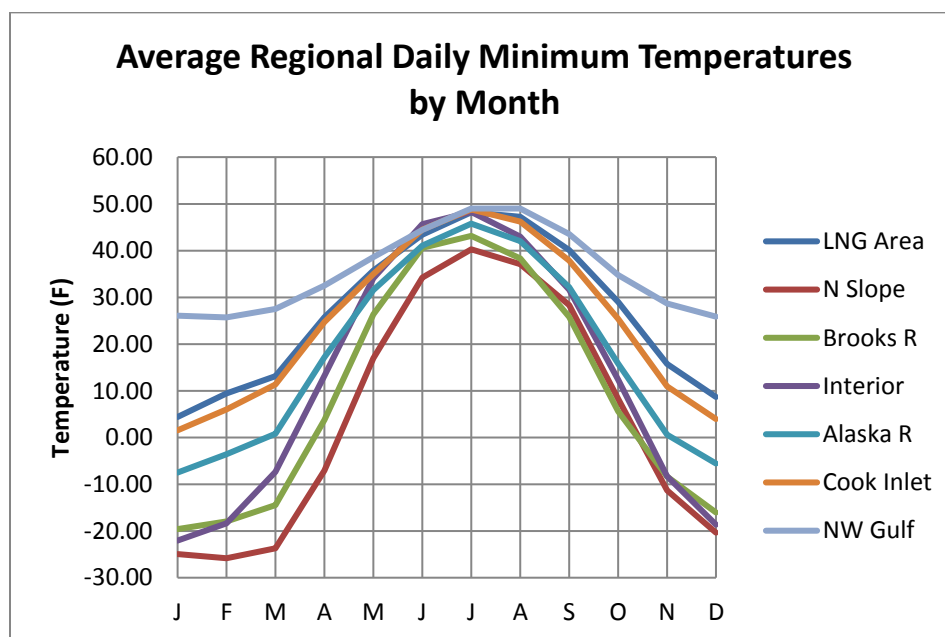


FIGURE 9.2.1-4 Average Regional Daily Minimum Temperatures by Month

Sources: See Appendix A

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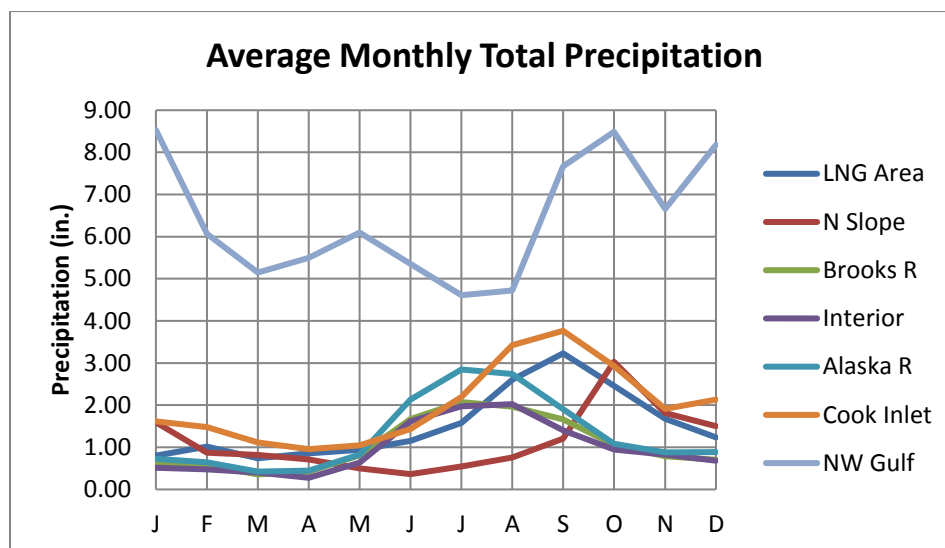


FIGURE 9.2.1-5 Average Monthly Total Precipitation

Sources: See Appendix A

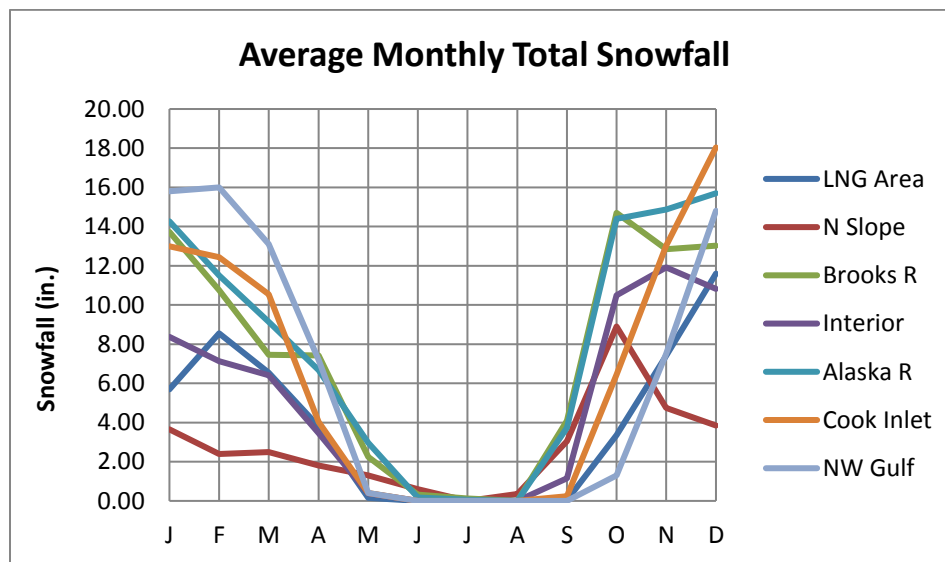


FIGURE 9.2.1-6 Average Monthly Total Snowfall

Sources: See Appendix A

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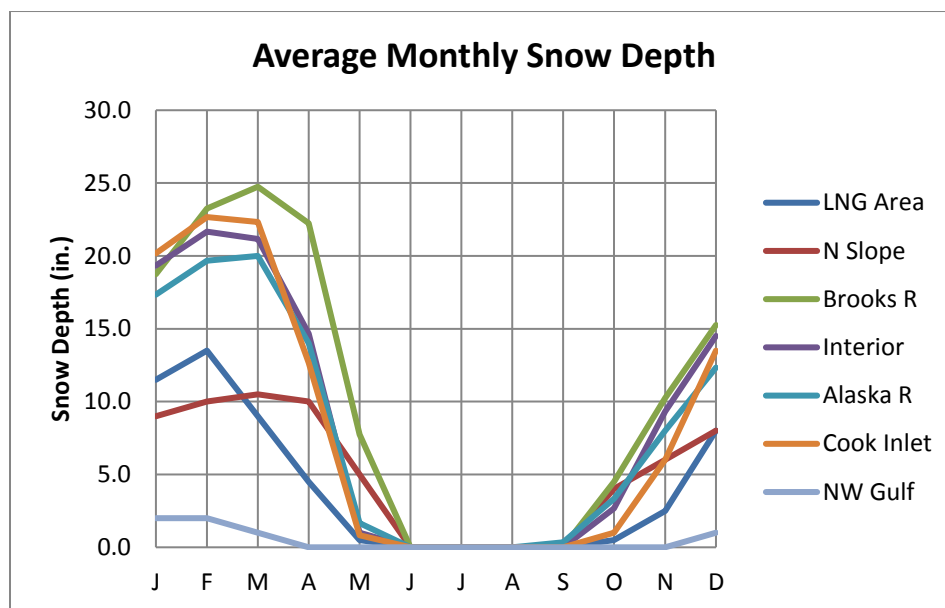


FIGURE 9.2.1-7 Average Monthly Snow Depth

Sources: See Appendix A

9.2.1.4 Summary of Meteorological Conditions

The following is a summary of the meteorological conditions within the Project area based on the information listed in Figures 9.2.1-3 through 9.2.1-7 and Appendix A.

9.2.1.4.1 Temperature

Based on available data detailed in Appendix A, the coldest locations in the Project area are (1) on the North Slope at Prudhoe Bay and Deadhorse and (2) on the north side of the Brooks Range near Galbraith Lake. Extreme cold persists in the winter months over the North Slope, with daily average temperatures below 0 °F during the months of December through March. In July and August, average daily high temperatures are above 50 °F, with average daily lows above freezing.

The Central Interior of Alaska exhibits the largest seasonal range in temperatures, as well as the largest daily range of temperatures. Extremely cold weather can persist during the winter months, with occasional two- or three-week periods of temperatures below -40 °F. The coldest temperature recorded in the Project vicinity was in the -80 °F range at Prospect Creek on January 23, 1971. In the summer months, average high temperatures are above 70 °F, with occasional days above 90 °F. The warmest location in the Project vicinity is around Fairbanks. The warmest summer temperature recorded in the Project vicinity was at Fairbanks, which reached 96 °F on June 15, 1969.

In the Cook Inlet region, temperature ranges are more moderate, with average summer temperatures in the 60 °F range and winter temperatures in the 20 °F range. The Northwest Gulf division has the mildest temperature conditions of all these regions, with average wintertime temperatures higher than the other

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regions. In the transition zone, temperatures are slightly cooler but still exhibit a comparatively moderate annual and daily temperature range.

9.2.1.4.2 Precipitation

A clear seasonal cycle in average precipitation is evident for all climate divisions, but less pronounced in the Northwest Gulf division. Other regions show a clear maximum precipitation pattern in the late summer and fall months, with a sharp peak in October for the North Slope. Precipitation on the North Slope is generally low, with an average of fewer than 10 inches per year. The Brooks Range and areas just south have a relatively high amount of snowfall (70 inches or more annually). The maximum annual snowfall recorded in the Project area was at Prospect Creek with more than 163 inches of snow in 1971.

As a location representative of the Central Interior of Alaska, Fairbanks receives 65 inches of snow per year, on average. Total annual precipitation generally averages more than 10 inches per year, with the bulk of that amount occurring as rainfall during the summer months.

Precipitation in the Cook Inlet region is both heavier and more frequent than in the other areas, generally occurring throughout the year. The Northwest Gulf division has the highest average precipitation, and it generally occurs in all months. Some areas in the Alaska Range have precipitation averages more than 60 inches per year. Relatively heavy precipitation can also occur with the passage of large mid-latitude cyclone systems.

Snowfall often occurs in the region from October through April, with relatively high monthly average snow depth in the late winter and early spring months.

9.2.1.4.3 Relative Humidity

Humidity and dew point data are not available for many Alaska meteorological stations; however, NCDC has reported average humidity for some areas. The annual average relative humidity at Fairbanks and Bettles are both around 60 percent.

9.2.1.4.4 Wind

The more-exposed North Slope locations experience much stronger wind speeds than the rest of the Project area. Except for localized strong wind conditions from passing storms, winds are generally light in the Central Interior of Alaska, especially at lower elevations.

Wind speed data (speed and direction) are sparse at most of the stations within the Project vicinity; however, wind speed has been recorded at Fairbanks and Bettles. In Fairbanks, the highest wind speeds occur during the summer with an annual mean wind speed of 5.4 miles per hour (mph). The prevailing wind direction recorded at the Fairbanks Airport is from the north. Blizzard conditions are almost never seen, as winds in Fairbanks are above 20 mph less than 1 percent of the time. The Bettles station seldom sees strong winds during any season of the year or any significant directional variation from a prevailing northerly wind (WRCC, 2011). In Cook Inlet, stronger winds generally occur with passing mid-latitude storms and higher than average winds are found along exposed ridges and coastlines.

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Local windflow patterns tend to be channeled or diverted by topographical features, such as mountain passes, valleys, and waterbodies. Thus, due to the complex terrain found in the Brooks and Alaska Ranges, wind speeds and directions are expected to be highly localized due to long-valley channeling and cross-valley slope flow. Wind roses for individual project site locations are provided in the modeling reports in Appendices D, E, and F.

9.2.1.4.5 Fog, Clouds, and Visibility

Fog forms when the dew point temperature equals the ambient temperature. Except on the North Slope, fog rarely forms in the summer in Alaska because the ambient temperature is significantly higher than the dew point temperature, even near waterbodies. Spring and fall are the times of the year when fog is more likely to form, especially in areas near large waterbodies that have higher dew point temperatures. Fog is almost always less than 300 feet thick, so the surrounding uplands are usually clear, with warmer temperatures. A dense “ice fog,” composed of suspended fine ice crystals, develops at times in the Interior of Alaska and on the North Slope, and visibility in the ice fog is sometimes quite low, hindering aircraft operations for as much as a day in severe cases (WRCC, 2011).

Central Interior Alaska winter temperatures can reach low enough levels (-20 °F to -60 °F) to create ice fog on a fairly frequent basis. As cold air is denser, cold high-pressure systems are formed, which are very difficult to displace. Thus, stable conditions with no wind can persist for several days to weeks, causing long-lasting ice fogs in Interior locations (NCDC, 2011). Cold snaps in Fairbanks accompanied by winter ice fog generally last about a week, but these conditions can last up to three weeks in unusual situations.

Cloud cover and storm observations are also limited in the Project vicinity. In Fairbanks and Bettles, cloudy days occur for approximately 200 days of the year, while 90 days per year are partly cloudy, and approximately 70 days are clear (NCDC, 2011).

9.2.2 Existing Ambient Air Quality

9.2.2.1 Ambient Air Quality Standards

Federal and state air emissions regulations are designed to ensure that new sources do not cause or contribute to an exceedance of ambient standards for criteria air pollutants. The criteria pollutants are as follows: sulfur dioxide (SO₂); carbon monoxide (CO); nitrogen dioxide (NO₂); ozone (O₃); particulate matter having an aerodynamic diameter of 10 microns or less (PM₁₀); particulate matter having an aerodynamic diameter of 2.5 microns or less (PM_{2.5}); and lead (Pb).

EPA has established National Ambient Air Quality Standards (NAAQS) for these seven pollutants. The NAAQS are set at levels EPA believes are necessary to protect public health (primary standards) and welfare (secondary standards).

The Alaska Department of Environmental Conservation (ADEC) has established similar ambient air quality standards referred to as Alaska Ambient Air Quality Standards (AAAQS). AAAQS are similar to the federal NAAQS for criteria pollutants, except that ADEC has yet to remove the 24-hour and annual standards for SO₂. ADEC also has an eight-hour AAAQS for ammonia. Table 9.2.2-1 lists both the federal and state ambient air quality standards.

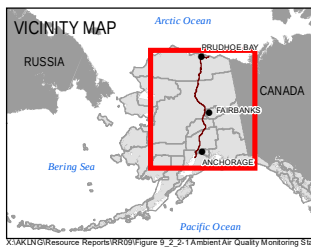
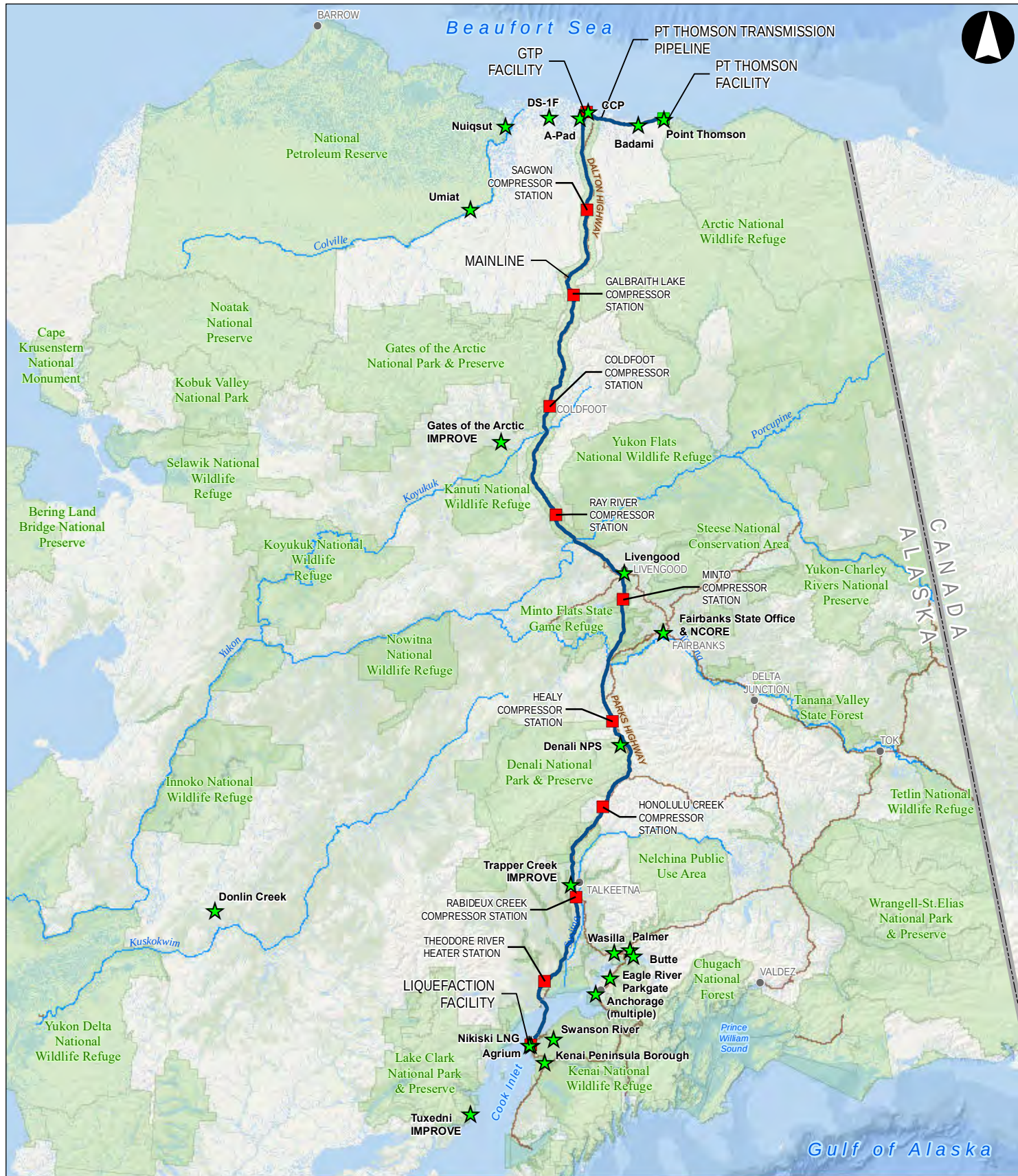
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TABLE 9.2.2-1 National and Alaska Ambient Air Quality Standards			
Air Pollutant	Averaging Period	NAAQS	AAAQS
Sulfur Dioxide	1-Hour ^a	75 ppbv	196 µg/m ³
	3-Hour ^b	0.5 ppmv	1,300 µg/m ³
	24-Hour ^b	---	365 µg/m ³
	Annual	---	80 µg/m ³
Carbon Monoxide	1-Hour ^b	35 ppmv	40 mg/m ³
	8-Hour ^b	9 ppmv	10 mg/m ³
Nitrogen Dioxide	1-Hour ^c	100 ppbv	188 µg/m ³
	Annual	53 ppbv	100 µg/m ³
Ozone	8-Hour ^d	0.070 ppmv	0.070 ppmv
Particulate Matter less than 10 Microns	24-Hour ^b	150 µg/m ³	150 µg/m ³
Particulate Matter less than 2.5 Microns	24-Hour ^e	35 µg/m ³	35 µg/m ³
	Annual	12 µg/m ³	12.0 µg/m ³
Lead	Rolling 3-Month Average	0.15 µg/m ³	0.15 µg/m ³
Ammonia	8-Hour ^b	----	2.1 mg/m ³
Sources: EPA 2015a; ADEC 2016a Abbreviations: --- = Not applicable µg/m ³ = micrograms per cubic meter mg/m ³ = milligrams per cubic meter ppbv = parts per billion by volume ppmv = parts per million by volume Notes: ^a Standard is attained when the 3-year average of the annual, 99 th percentile, daily maximum, one-hour concentration is less than or equal to 75 ppb, or 196 µg/m ³ . ^b Not to be exceeded more than once in a year. ^c Standard is attained when the 3-year average of the annual, 98 th percentile, daily maximum, one-hour concentration is less than or equal to 100 ppb, or 188 µg/m ³ . ^d Standard is attained when the 3-year average of the annual fourth-highest daily maximum eight-hour average ozone concentration is less than or equal to 0.070 ppm. ^e Standard is attained when the 3-year average of the annual 98 th percentile 24-hour concentration is less than or equal to 35 µg/m ³ .			

9.2.2.2 Existing Air Quality Concentrations

Air quality data were gathered from all publicly available sources in the Project vicinity and evaluated for data quality. Figure 9.2.2-1 shows the locations of monitoring stations with data that are reasonably current (generally collected since 2010), complete (80 percent or better data capture), and publicly available. Existing air quality data from these stations, which depict the regional air quality conditions, are summarized in Appendix B.

These monitoring stations are operated by private entities and local, state, or federal agencies. Privately collected datasets are generally for Prevention of Significant Deterioration (PSD) monitoring programs.



LEGEND

- Project Facility
- Existing Facility
- ★ Ambient Air Quality Monitoring Stations
- Alaska LNG Rev C2 Route
- Major Highways
- Major Rivers
- State and Federal Conservation Lands

0 25 50 100 150 Miles

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AMBIENT AIR QUALITY MONITORING STATIONS

FIGURE 9.2.2-1

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Local, state, and federal monitoring stations include State and Local Air Monitoring Stations (SLAMS) (EPA 2014a), Interagency Monitoring of Protected Visual Environments (IMPROVE), National Core Network (NCore), and Clean Air Status and Trends Network (CASTNET). Certain SLAMS PM_{2.5} monitoring data are also part of the Chemical Speciation Network (CSN). Although data from the SLAMS and related ambient air monitoring networks may not necessarily meet all of the PSD criteria, data collected at these stations are valuable in describing the existing ambient air quality of the Project area, particularly because much of the Project area in the vicinity of the Mainline route has limited air quality monitoring data available.

Some data presented in Appendix B were collected by Special Purpose Monitors (SPMs). However, SPM data are not to be used for NAAQS compliance demonstrations without review and acceptance as required in 40 C.F.R. 58.20. The concentrations measured by SPMs have been included in this Resource Report to ensure a complete presentation of existing air quality.

Monitoring data from Appendix B are summarized in Tables 9.2.2-2, 9.2.2-3, and 9.2.2-4 for the North Slope, Interior Alaska and Alaska Range, and Southcentral Alaska and Cook Inlet. Those tables also provide the most representative air quality level that is available from existing data at the time of this submittal. However, updates to these air quality levels may be provided from later monitoring efforts as background concentrations for the required air quality analyses. For the most part, the data demonstrate that existing air quality complies with the ambient standards. Data collected at certain stations indicate levels above the air quality standards, but which do not necessarily indicate an exceedance of the standards. While these data are included for completeness, the higher levels are not necessarily representative of air quality at Project facilities, but rather reflect local circumstances (such as the Fairbanks PM_{2.5} nonattainment area [see Section 9.2.2.3.2]) or exceptional events (such as forest fires).

There are seven available datasets on the North Slope, which provide a good representation of air quality at North Slope oil and gas production facilities as well as remote areas.

In the Interior, there are limited data. The most complete Interior dataset is being collected in the Fairbanks urban area, which is nonattainment for PM_{2.5} and not representative of the Project Mainline corridor. Outside of Fairbanks and Healy, Interior Alaska is sparsely populated with few existing significant sources of air pollutants near the Project area.

In Southcentral Alaska, there are several data collection programs with special purposes, but few complete PSD monitoring programs. Many of these monitoring programs were established to gather specific data for the Anchorage urban area or to characterize fugitive dust issues in the Matanuska Valley. Thus, datasets should be carefully evaluated before identifying the best one for representing air quality at Project facilities. Rather than using existing publicly available datasets to characterize ambient air quality in the vicinity of the Liquefaction Facility, the Project initiated its own background data collection program beginning on January 1, 2015. The air quality station location is identified as the background station in Figure 9.2.2-2. Air quality data being collected at this station includes CO, NO₂, SO₂, O₃, PM₁₀, and PM_{2.5}. Prior to choosing this monitoring site and the air quality parameters, the Project representatives consulted with and received approval from ADEC (Alaska LNG Project, 2015). Data from the background station are included in this Resource Report for the Liquefaction Facility (see Appendix B).

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Representative air quality data for Project impact analyses are presented as part of the impact assessment in Section 9.2.5.

TABLE 9.2.2-2 Monitored Air Quality Data from the North Slope				
Air Pollutant	Averaging Period	Range of Maximum Monitored Concentrations ^a	Representative Background Concentration at GTP	Standard
Sulfur Dioxide	1-Hour ^b	6.29 – 75.9 µg/m ³	9.39 µg/m ³	196 µg/m ³
	3-Hour	5.5 – 65.5 µg/m ³	20.96 µg/m ³	1,300 µg/m ³
	24-Hour	3.0 – 26.0 µg/m ³	8.12 µg/m ³	365 µg/m ³
	Annual	0.3 – 5.2 µg/m ³	1.8 µg/m ³	80 µg/m ³
Carbon Monoxide	1-Hour	0.0022 – 1.36 mg/m ³	1.15 mg/m ³	40 mg/m ³
	8-Hour	0.0013 – 1.15 mg/m ³	1.15 mg/m ³	10 mg/m ³
Nitrogen Dioxide	1-Hour ^c	61.69 – 471.4 µg/m ³	61.69 µg/m ³	188 µg/m ³
	Annual	1.88 – 20.6 µg/m ³	6.0 µg/m ³	100 µg/m ³
Ozone	8-Hour ^d	0.047 – 0.056 ppmv	0.056 ppmv	0.070 ppmv
Particulate Matter less than 10 Microns	24-hour	35.6– 70 µg/m ³	50.0 µg/m ³	150 µg/m ³
Particulate Matter less than 2.5 Microns	24-Hour ^e	9 – 22.5 µg/m ³	15 µg/m ³	35 µg/m ³
	Annual	2.1 – 3.7 µg/m ³	3.7 µg/m ³	12 µg/m ³
Source: See Appendix B for the datasets and methodology for selection of monitored concentrations. Abbreviations: µg/m³ – micrograms per cubic meter mg/m³ – milligrams per cubic meter ppmv – parts per million by volume Notes: ^a Concentrations for the short-term standards (1 to 24 hours) are based on the design calculations for the standards. See notes in Table 9.2.2-1. ^b The one-hour SO₂ average shown in the table reflects the annual 99th percentile of the daily maximum one-hour SO₂ concentration averaged over the specified monitoring period are provided for informational purposes; and for PSD-quality determination purposes for future permitting projects. ^c The one-hour average shown in the table reflects annual 98th percentile of the daily maximum one-hour NO₂ concentration averaged over the specified monitoring period are provided for informational purposes; and for PSD-quality determination purposes for future permitting projects. ^d The annual fourth-highest daily maximum eight-hour O₃ concentrations averaged over the specified monitoring period are provided for informational purposes; and for PSD-quality determination purposes for future permitting projects. ^e The annual 98th percentile PM_{2.5} concentrations averaged over the specified monitoring period are provided for informational purposes; and for PSD-quality determination purposes for future permitting projects.				

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TABLE 9.2.2-3

Monitored Air Quality Data from Interior Alaska and the Alaska Range

Air Pollutant	Averaging Period	Range of Maximum Monitored Concentrations ^a	Standard
Sulfur Dioxide	1-Hour ^b	146.5 µg/m ³	196 µg/m ³
	3-Hour	5.33 – 131 µg/m ³	1,300 µg/m ³
	24-Hour	5.33 – 85.9 µg/m ³	365 µg/m ³
	Annual	1.33 – 33.2 µg/m ³	80 µg/m ³
Carbon Monoxide	1-Hour	0.7 – 5.41 mg/m ³	40 mg/m ³
	8-Hour	0.3 – 3.21 mg/m ³	10 mg/m ³
Nitrogen Dioxide	1-Hour ^c	26.32 µg/m ³	188 µg/m ³
	Annual	1.91 µg/m ³	100 µg/m ³
Ozone	8-Hour ^d	0.054 – 0.064 ppmv	0.070 ppmv
Particulate Matter less than 10 Microns	24-hour	15 – 111 µg/m ³	150 µg/m ³
Particulate Matter less than 2.5 Microns	24-Hour ^e	11.2 – 83.2 ^f µg/m ³	35 µg/m ³
	Annual	1.45 – 13.2 ^f µg/m ³	12 µg/m ³

Source: See Appendix B for the datasets and methodology for selection of monitored concentrations.

Abbreviations:

µg/m³ – micrograms per cubic meter

mg/m³ – milligrams per cubic meter

ppmv – parts per million by volume

Notes:

^a Concentrations for the short-term standards (1 to 24 hours) are based on the design calculations for the standards. See notes in Table 9.2.2-1

^b The one-hour SO₂ average shown in the table reflects the annual 99th percentile of the daily maximum one-hour SO₂ concentration averaged over the specified monitoring period are provided for informational purposes; and for PSD-quality determination purposes for future permitting projects.

^c The one-hour average shown in the table reflects annual 98th percentile of the daily maximum one-hour NO₂ concentration averaged over the specified monitoring period are provided for informational purposes; and for PSD-quality determination purposes for future permitting projects.

^d The annual fourth-highest daily maximum eight-hour O₃ concentrations averaged over the specified monitoring period are provided for informational purposes; and for PSD-quality determination purposes for future permitting projects.

^e The annual 98th percentile PM_{2.5} concentrations averaged over the specified monitoring period are provided for informational purposes; and for PSD-quality determination purposes for future permitting projects.

^f Includes measured concentrations from the Fairbanks urban PM_{2.5} nonattainment area.

Note: See Section 9.2.5.2 for concentrations at each compressor station site.

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TABLE 9.2.2-4

Monitored Air Quality Data from Southcentral Alaska and Cook Inlet

Air Pollutant	Averaging Period	Range of Maximum Monitored Concentrations ^a	Representative Background Concentration at the LNG Plant	Standard
Sulfur Dioxide	1-Hour ^b	8.1 µg/m ³	5.0 µg/m ³	196 µg/m ³
	3-Hour	5.0 µg/m ³	5.0 µg/m ³	1,300 µg/m ³
	24-Hour	2.4 µg/m ³	2.4 µg/m ³	365 µg/m ³
	Annual	0.0 µg/m ³	0.0 µg/m ³	80 µg/m ³
Carbon Monoxide	1-Hour	1.1 – 9.39 mg/m ³	1.145 mg/m ³	40 mg/m ³
	8-Hour	1.1 – 7.9 mg/m ³	1.145 mg/m ³	10 mg/m ³
Nitrogen Dioxide	1-Hour ^c	35.7 – 222.6 ^f µg/m ³	32.3 µg/m ³	188 µg/m ³
	Annual	2.6 – 28.2 µg/m ³	2.6 µg/m ³	100 µg/m ³
Ozone	8-Hour ^d	0.048 – 0.061 ppmv	0.047 ppmv	0.070 ppmv
Particulate Matter less than 10 Microns	24-hour	35.2 – 376 ^g µg/m ³	40 µg/m ³	150 µg/m ³
Particulate Matter less than 2.5 Microns	24-Hour ^e	8.7 – 70.7 ^g µg/m ³	12 µg/m ³	35 µg/m ³
	Annual	0.94 – 7.94 ^g µg/m ³	3.7 µg/m ³	12 µg/m ³

Source: See Appendix B for the datasets and methodology for selection of monitored concentrations.

Abbreviations:

µg/m³ – micrograms per cubic meter

mg/m³ – milligrams per cubic meter

ppmv – parts per million by volume

Notes:

^a Concentrations for the short-term standards (1 to 24 hours) are based on the design calculations for the standards. See notes in Table 9.2.2-1

^b The one-hour SO₂ average shown in the table reflects the annual 99th percentile of the daily maximum one-hour SO₂ concentration averaged over the specified monitoring period are provided for informational purposes; and for PSD-quality determination purposes for future permitting projects.

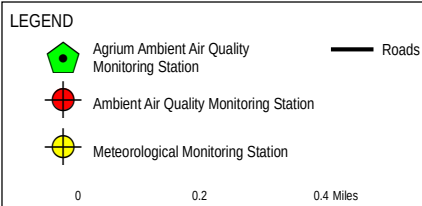
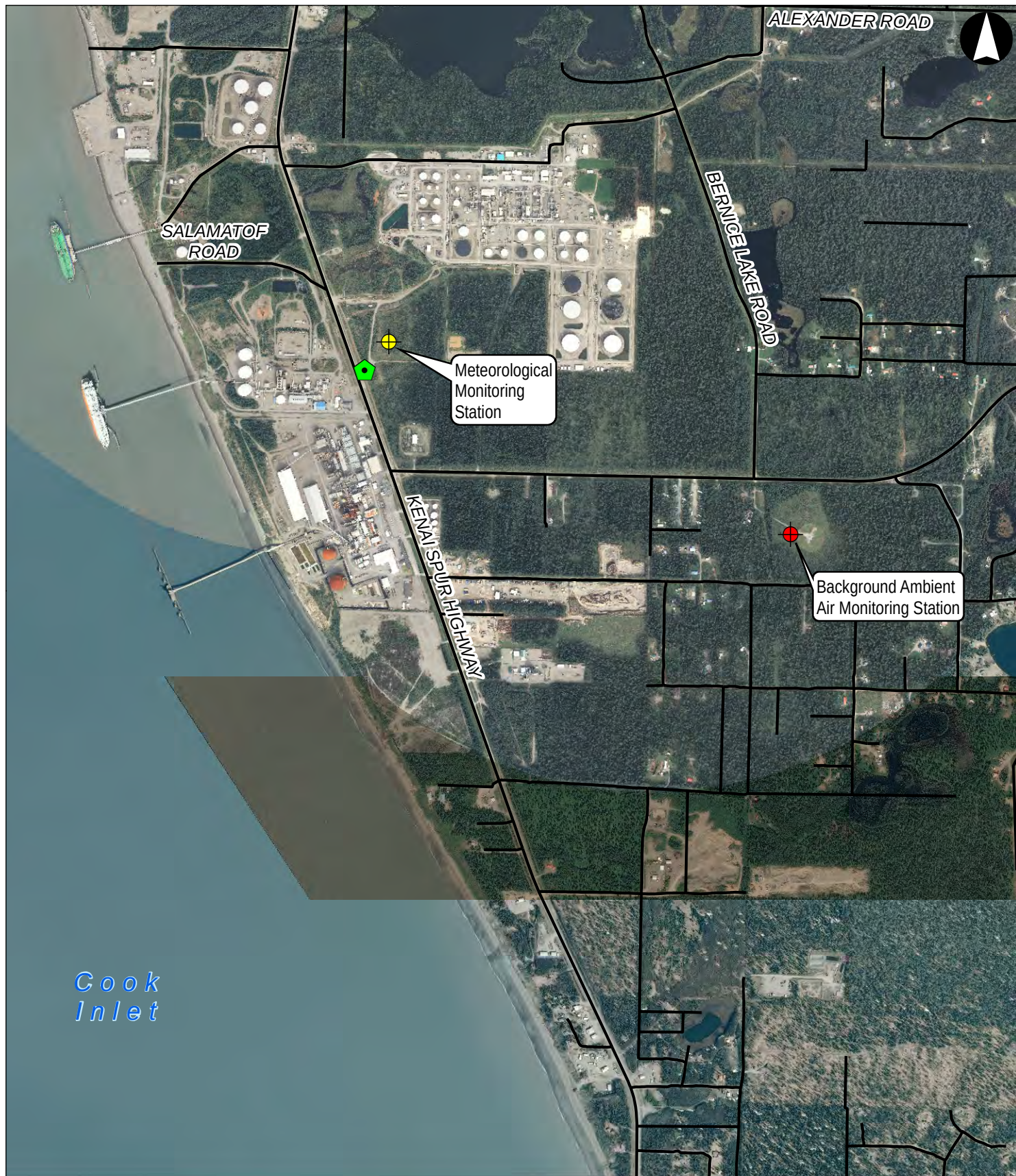
^c The 1-hour average shown in the table reflects annual 98th percentile of the daily maximum one-hour NO₂ concentration averaged over the specified monitoring period are provided for informational purposes; and for PSD-quality determination purposes for future permitting projects.

^d The annual fourth-highest daily maximum eight-hour O₃ concentrations averaged over the specified monitoring period are provided for informational purposes; and for PSD-quality determination purposes for future permitting projects.

^e The annual 98th percentile PM_{2.5} concentrations averaged over the specified monitoring period are provided for informational purposes; and for PSD-quality determination purposes for future permitting projects.

^f Includes measured concentrations from the Anchorage urban area.

^g Includes data from several special purpose monitoring stations in Anchorage and the Matanuska Valley.



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LIQUEFACTION FACILITY AMBIENT AIR MONITORING AND METEOROLOGICAL STATION LOCATIONS

FIGURE 9.2.2-2

ALASKA LNG

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9.2.2.3 Existing Ambient Air Quality Management and Regulation

9.2.2.3.1 Air Quality Control Regions

Air quality in Alaska is regulated by ADEC through an approved State Implementation Plan (SIP) for air quality. The specific regulations that may apply to the Project are identified in Sections 9.2.4 (construction) and 9.2.6 (operations). The Alaska SIP divides the state into four separate Air Quality Control Regions:

- AQCR 008³ – Cook Inlet Intrastate Air Quality Control Region;
- AQCR 009 – Northern Alaska Intrastate Air Quality Control Region;
- AQCR 010 – South Central Alaska Intrastate Air Quality Control Region; and
- AQCR 011 – Southeastern Alaska Intrastate Air Quality Control Region.

A depiction of the Air Quality Control Regions is provided in Figure 9.2.2-3. The Project involves only two of the regions, the Cook Inlet and Northern Alaska Regions, which are generally separated by the center of the Alaska Range (ADEC, 1972).

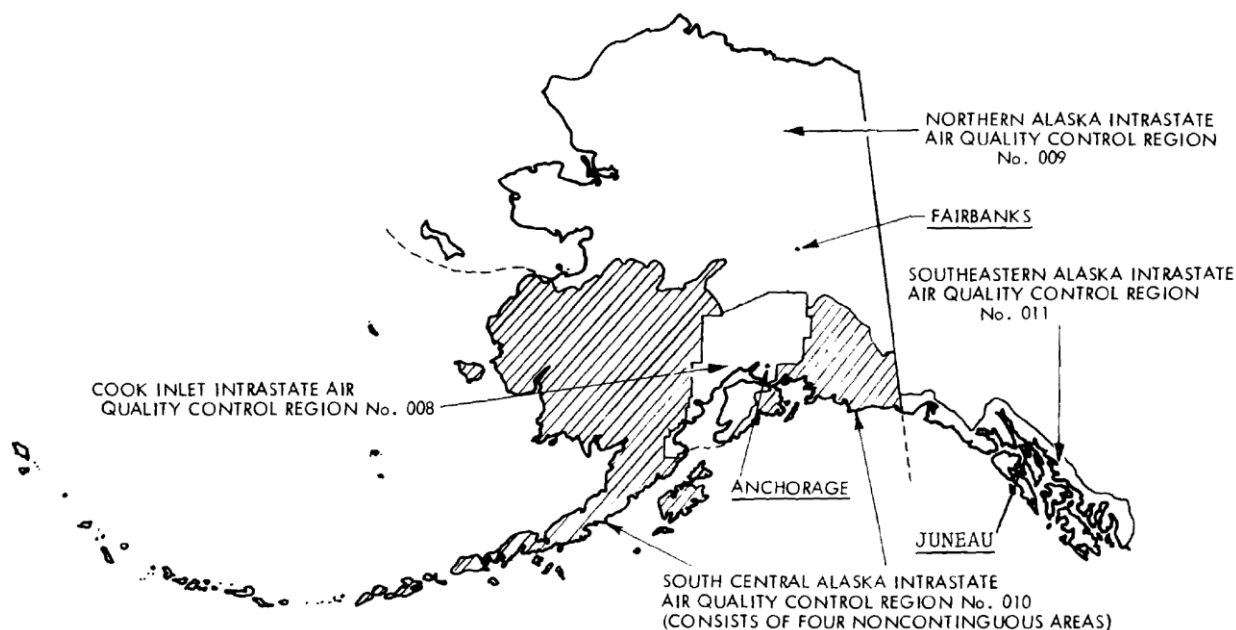


FIGURE 9.2.2-3 Alaska Air Quality Control Regions

³ Air Quality Control Region numbers are established nationally for all states in alphabetical order. Alaska begins with AQCR 008.

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Air quality is regulated by the federal Clean Air Act (CAA) in part through its PSD rules implemented in 40 C.F.R. §52.21 and in the Alaska Administrative Code (AAC) 18 AAC 50.020. The PSD rules limit the future increases in ambient air concentrations of NO₂, SO₂, PM₁₀, and PM_{2.5}, and establish “minor source baseline dates” for determining a date, after which the air quality deterioration must be within the PSD increments or regulatory limits. The baseline dates are established for all Air Quality Control Regions in 18 AAC 50.020, and are also provided in Table 9.2.2-5.

The Cook Inlet and Northern Alaska Air Quality Control Regions are relevant to the Project. Increases in emissions after the baseline dates for each of the four respective pollutants consume part of the allowable ambient air quality increment within the respective regions. This increment consumption is formally regulated on a source-specific permitting basis, as discussed in Sections 9.2.5.1 and 9.2.5.2.

TABLE 9.2.2-5 Alaska Baseline Areas and Dates		
Baseline Area	Air Pollutant	Minor Source Baseline Date
Cook Inlet Intrastate Air Quality Control Region	Nitrogen dioxide	February 8, 1988
	Sulfur dioxide	October 12, 1979
	PM-10	March 20, 1982
	PM-2.5	September 14, 2012
Northern Alaska Intrastate Air Quality Control Region	Nitrogen dioxide	February 8, 1988
	Sulfur dioxide	June 1, 1979
	PM-10	November 13, 1978
	PM-2.5	November 2, 2012
South Central Alaska Intrastate Air Quality Control Region	Nitrogen dioxide	February 8, 1988
	Sulfur dioxide	October 26, 1979
	PM-10	October 26, 1979
	PM-2.5	October 15, 2015
Southeast Alaska Intrastate Air Quality Control Region	Nitrogen dioxide	February 8, 1988
	Sulfur dioxide	November 10, 1986
	PM-10	To be established under 40 C.F.R. 52.21(b)(14)(ii), adopted by reference in 18 AAC 50.040(h)
	PM-2.5	To be established under 40 C.F.R. 52.21(b)(14)(ii), adopted by reference in 18 AAC 50.040(h)
Source: 18 AAC 50.020 (ADEC 2016b)		

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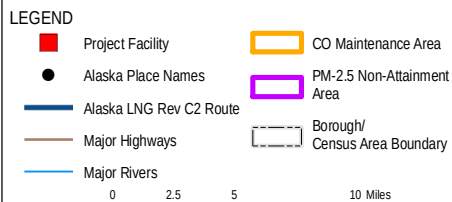
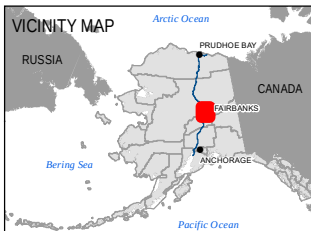
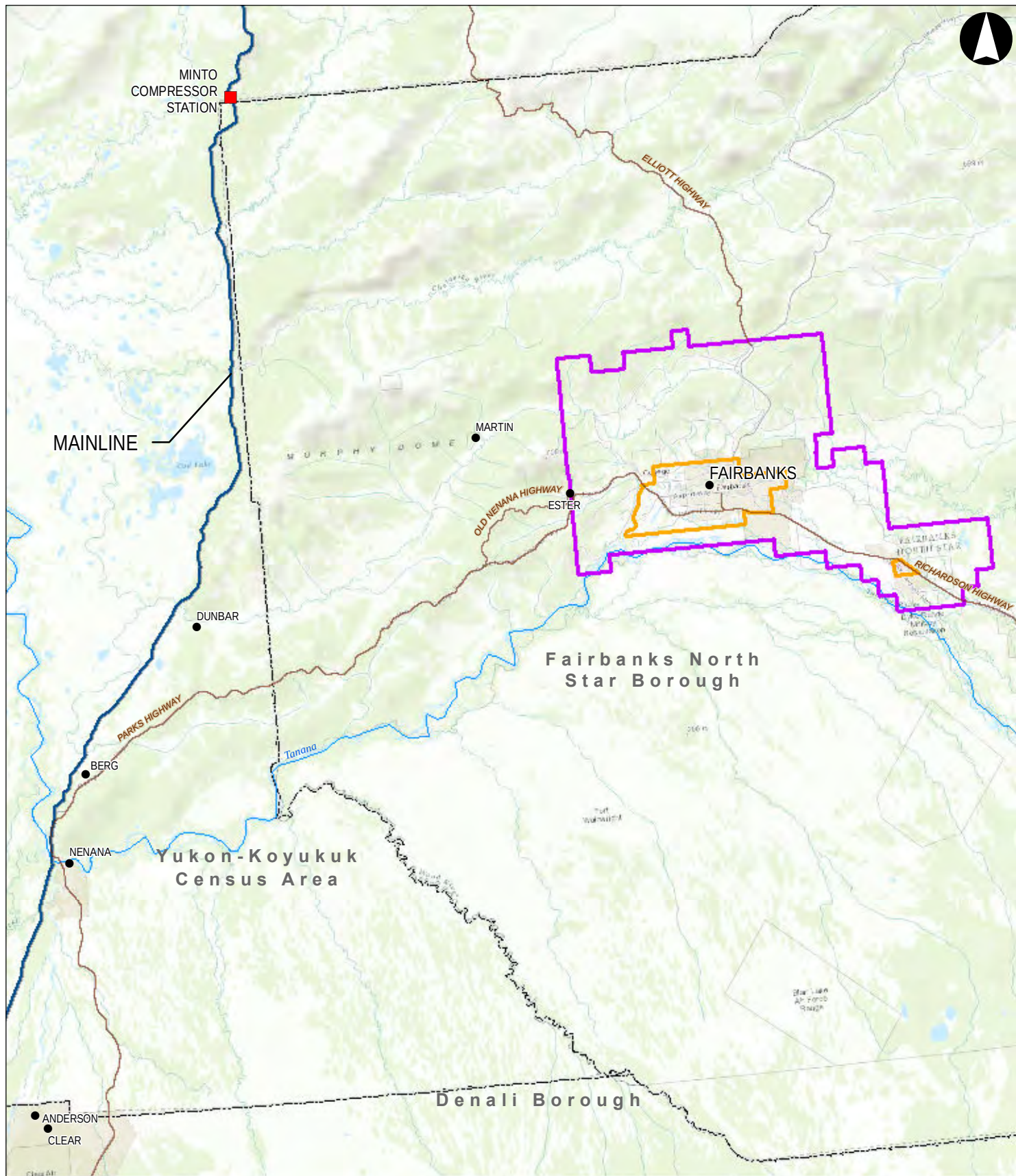
9.2.2.3.2 NAAQS Attainment and Non-Attainment Areas

The CAA requires geographic areas that do not meet a particular NAAQS to be designated as “non-attainment” for that individual standard. Other areas can be designated as “in attainment” if data show that the area meets the standard, as “unclassified,” or as “unclassified/attainment” with respect to the standards. An area may also be designated as a “maintenance” area if it has previously been in non-attainment for a pollutant, but has since implemented a SIP that has brought the area back into attainment for the pollutant.

Alaska has one non-attainment area and four maintenance areas (ADEC, 2016b; EPA, 2015b; and 40 C.F.R 81.302). The Fairbanks and North Pole urban area is designated as non-attainment for PM_{2.5}.⁴ The Mendenhall Valley in the City and Borough of Juneau and the Eagle River area in the Municipality of Anchorage are designated as maintenance areas for PM₁₀. The Municipality of Anchorage and the Fairbanks and North Pole urban area are designated as maintenance areas for CO. ADEC’s SIP describes how the State of Alaska will comply with the CAA and achieve attainment with the NAAQS and/or AAAQS.

The Project area is currently designated as attainment or unclassified for all criteria pollutants. A short segment of the Mainline corridor extends into the Fairbanks North Star Borough, but the location of the Project corridor and nearest compressor station (Minto) is approximately 21 miles west and 25 miles northwest, respectively, of the border of the established PM_{2.5} non-attainment area and a greater distance from the Fairbanks CO maintenance area. Figures 9.2.2-4 and 9.2.2-5, respectively, provide the proximity of the Project to the Fairbanks and Anchorage non-attainment and maintenance areas.

⁴ On November 20, 2015, ADEC filed a request with EPA to divide the Fairbanks PM_{2.5} non-attainment area into two non-attainment areas—a western area that would include the City of Fairbanks and an eastern area that would include the City of North Pole. ADEC states that dividing into two areas would allow development of air quality plans and controls tailored to the situation in each area.



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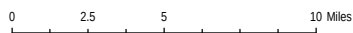
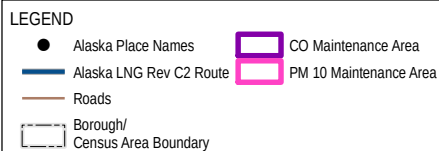
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**FAIRBANKS AIR QUALITY
NON-ATTAINMENT AND
MAINTENANCE AREAS**

FIGURE 9.2.2-4

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**ANCHORAGE AIR QUALITY
MAINTENANCE AREAS**

FIGURE 9.2.2-5

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9.2.2.3.3 PSD Class I Areas

Under the CAA, certain lands are designated as Class I Areas. Class I Areas are so designated because their air quality is considered a special attribute of these locations (e.g., national parks, wilderness areas). Class I Areas have more stringent requirements for incremental changes in criteria pollutant concentrations and impacts on air quality related values (AQRVs), such as visibility and acidic deposition.

There are four Class I areas in the State of Alaska (EPA, 2011):

- Bering Sea Wilderness Area;
- Denali National Park and Preserve (DNPP);
- Simeonof Wilderness Area; and
- Tuxedni Wilderness Area.

As shown on Figure 9.2.2-6, the Tuxedni Wilderness Area and DNPP are the Class I areas in proximity to the Project. The Liquefaction Facility is the only Project PSD facility within 300 kilometers of a Class I area. The Liquefaction Facility is estimated to be approximately 50 miles (80 kilometers) from the Tuxedni Wilderness Area, which is southwest of the Liquefaction Facility and across Cook Inlet. The Liquefaction Facility is about 115 miles (185 kilometers) from DNPP. LNGC traffic traversing Cook Inlet could travel within approximately 12 to 19 miles (20 to 30 kilometers) of the Tuxedni Class I area. In some areas, the Mainline corridor approaches within less than 1 mile of the eastern boundary of DNPP; however, there are no PSD-reviewed facilities to be constructed along this corridor⁵.

9.2.2.3.4 Sensitive Class II Areas

In addition to PSD Class I Areas, federal land managers (FLMs) have identified “Sensitive Class II Areas,” which are federal conservation units deemed to merit analysis of ambient air quality and AQRVs. Through consultation with FLMs, the following Sensitive Class II Areas and the respective Federal Land Management agencies have been identified for further analysis of impacts from the Project:

- Arctic National Wildlife Refuge (NWR) (U.S. Fish and Wildlife Service [USFWS]);
- Gates of the Arctic National Park and Preserve (National Park Service [NPS]);
- Kanuti NWR (USFWS);
- Yukon Flats NWR (USFWS);
- Lake Clark National Park and Preserve (NPS);
- Kenai NWR (USFWS);
- Chugach National Forest (U.S. Forest Service [USFS]);
- Kenai Fjords National Park (NPS); and
- Kodiak NWR (USFWS).

⁵ Air-shed impacts at DNPP would be considered for nearby compressor station/heater station facilities. See locations in Section 9.2.2.3.4.

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Figure 9.2.2-7 shows where these Class I and Sensitive Class II Areas are in relationship to Project facilities.

9.2.2.3.5 Air Quality Related Values (AQRVs)

AQRVs are resources, as defined by FLMs, that may be adversely affected by a change in air quality, and include visibility (either regional haze or plume impairment) and sulfur and nitrogen deposition, often called “acid deposition.” The FLMs’ AQRV Work Group (FLAG) issued a guidance document (FLAG 2010) for the methodology and AQRV criteria used to evaluate adverse impacts. This guidance and associated screening thresholds were developed primarily for evaluating impacts at Class I areas.

Because the AQRVs only have screening thresholds below which no concern exists, rather than strict regulatory standards, AQRV impacts are typically evaluated on a case-by-case basis by FLMs. As part of the impact evaluation, the FLMs consider such factors as magnitude, frequency, duration, location, geographic extent, timing of impacts and current and projected conditions of AQRVs. In practice, this methodology often results in the need to place AQRV impacts into context.

Note that the location of these Class I or Sensitive Class II areas in the near field (within approximately 50 kilometers) or in the far field (beyond approximately 50 kilometers) determines the applicable model and AQRVs to be evaluated. In the case of visibility, “plume impairment” is the AQRV analysis conducted in the near field whereas “regional haze” is the AQRV analyzed in the far field.

Plume Impairment

Plume impairment is generally defined as the pollutant loading of a portion of the atmosphere such that the plume becomes visible, by contrast or color difference, against a viewed background such as a landscape feature or the sky. The evaluation criteria for plume impairment are the color difference index (ΔE) and plume contrast (C_p). Plume impairment below the values in Table 9.2.2-6 are considered negligible and no further analysis is warranted. This AQRV is generally applicable for near-field (approximately less than 50 kilometers) source-receptor distances and modeled using the VISCREEN screening model or the PLUVUE II model if more information is required.

According to FLAG 2010, if the screening thresholds are met with VISCREEN, the FLM is likely not to object to the project on the basis of near-field visibility. If screening thresholds are not met, then use of the more refined PLUVUE II model can be implemented. The PLUVUE analysis provides additional information designed to assess the magnitude and frequency of plume impairment.

TABLE 9.2.2-6 Plume Impairment Initial Screening Thresholds		
Model	Color Difference Index (ΔE)	Contrast (C_p)
VISCREEN	2.0	0.05
PLUVUE II	1.0	0.02

Regional Haze

Visibility impairment is also manifested by the general alteration in the appearance of landscape features or the sky as the light between the observer and target becomes scattered or absorbed by pollutant loading

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in the atmosphere. This impairment results in a reduction of contrast between distant landscape features causing the view of the landscape features to deteriorate. This AQRV is generally applicable for far field (greater than approximately 50 kilometers) source-receptor distances or for multiple source analyses. CALPUFF is currently the recommended model to assess regional haze impacts using methodologies and inputs described in FLAG 2010.

Screening criteria, shown in Table 9.2.2-7, represent the incremental increases above a reference background level. According to FLAG 2010, if the 98th percentile change in light extinction is less than 5 percent, the visibility threshold of concern is not exceeded. Regional haze impacts due to project sources alone that are below this threshold are considered negligible and often no further analysis is warranted.

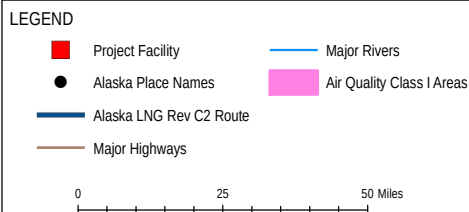
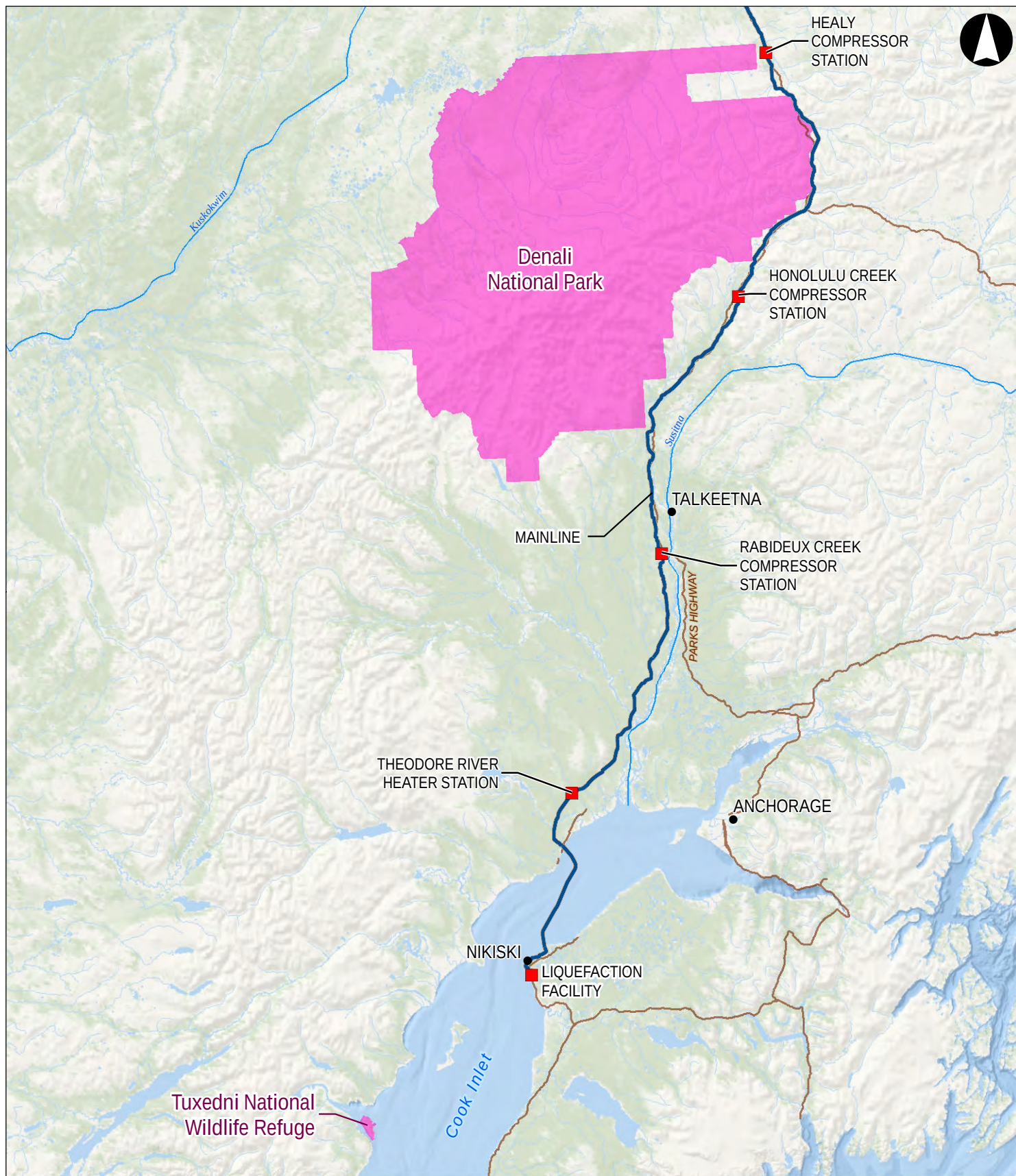
Cumulative regional haze impacts due to both project and offsite sources are typically compared to a 10 percent change in light extinction. If this threshold is exceeded at an area being evaluated, the FLM may consider the impacts on a case-by-case basis by taking into account the context when making an adverse impact determination.

TABLE 9.2.2-7 Regional Haze Initial Screening Thresholds	
Description	Change in Extinction
Contribute to visibility impairment	5%
Cause visibility impairment	10%

Acid Deposition

Increased nitrogen (N) or sulfur (S) deposition may result from emissions from new facilities and have a negative impact on AQRVs sensitive to N or S deposition. Dry and wet atmospheric deposition of N and S compounds is also an AQRV that is discussed in FLAG 2010. FLMs have established Deposition Analysis Thresholds (DATs), listed in Table 9.2.2-8 to use as screening levels for incremental increases in N or S compounds due to a proposed facility. Facility-only deposition of N or S below the DAT of 0.005 kilogram/hectare/year (kg/ha/yr) is considered negligible.

TABLE 9.2.2-8 Deposition Analysis Thresholds	
Pollutant	Facility Deposition (kg/ha/yr)
Nitrogen	0.005
Sulfur	0.005



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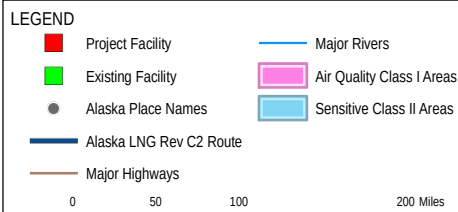
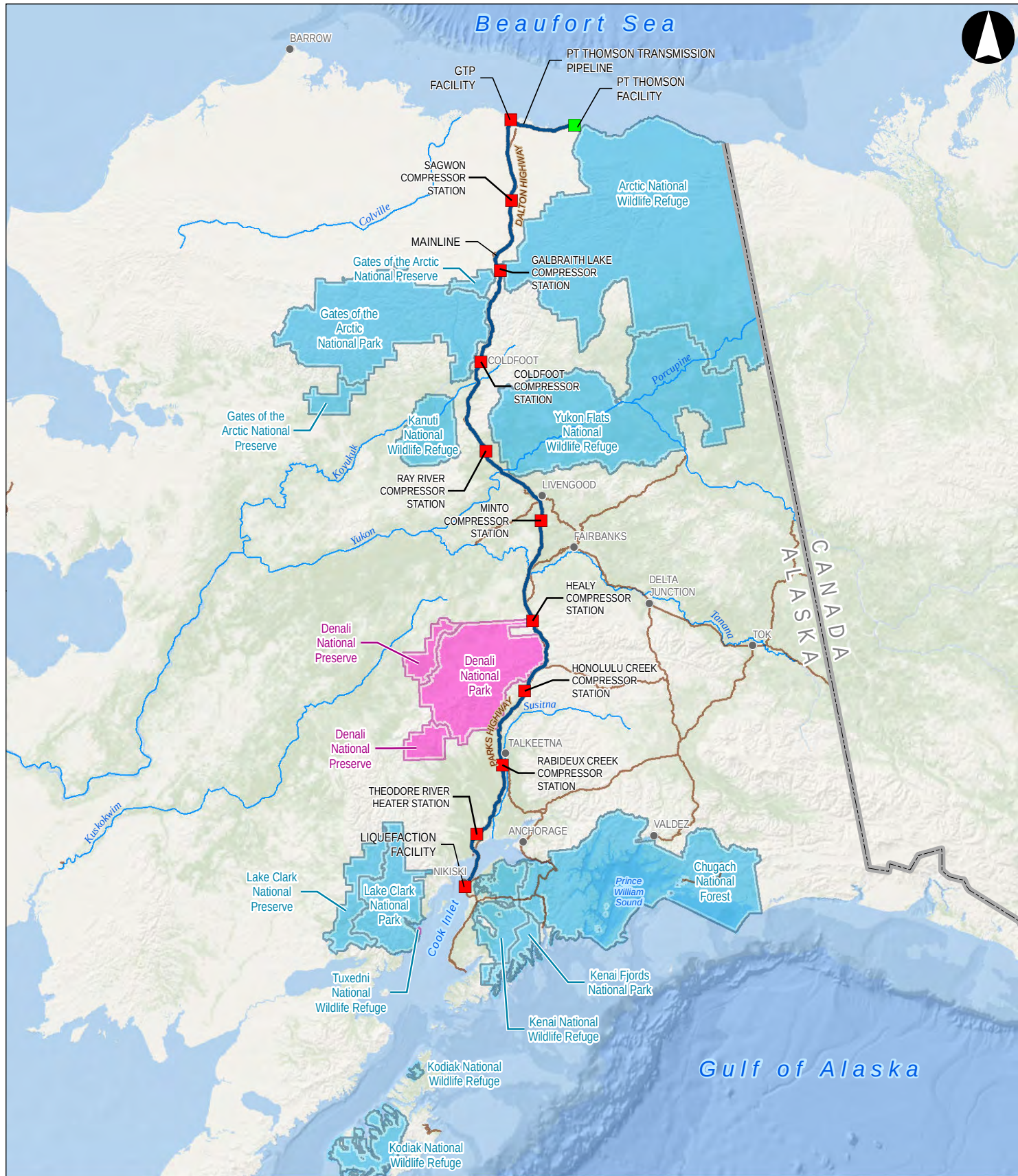
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**AIR QUALITY CLASS I AREAS
IN THE PROJECT VICINITY**

FIGURE 9.2.2-6

ALASKA LNG



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AIR QUALITY CLASS I AND SENSITIVE CLASS II AREAS IDENTIFIED FOR THE ALASKA LNG PROJECT

FIGURE 9.2.2-7

ALASKA LNG

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9.2.3 Air Quality Emissions and Potential Impacts from Construction Sources

Impacts to air quality from Project construction would include temporary emissions from construction equipment and support operations (e.g., construction camps), as well as fugitive dust from soil handling, storage, and replacement activities; and from gravel and other dust generating materials. This section provides a summary of estimated construction emissions for the major Project facilities, which are supported by calculations based on Project execution data provided in Appendix C: Emissions Associated with Project Construction.⁶ Emissions are also estimated for construction of marine systems and the marine offloading facility (MOF) at the Liquefaction Facility Marine Terminal, the marine component of the pipeline, and for construction of marine offloading facilities in support of the GTP construction. Construction emission details are based on information available to date.

9.2.3.1 Methodology for All Project Components

Project construction would result in air emissions of federal and Alaska criteria air pollutants (nitrogen oxides [NO_x], SO₂, CO, PM₁₀, PM_{2.5}, and volatile organic compounds [VOCs]) and greenhouse gases (GHGs) (carbon dioxide [CO₂], methane [CH₄], and nitrous oxide [N₂O]). Emissions of these pollutants are estimated from available data for the full range of construction activities, including combustion, non-combustion, and fugitive sources, using generally accepted emission factors for construction equipment and activity.

9.2.3.1.1.1 Combustion Emissions

Combustion sources include tailpipe emissions from heavy equipment (non-road engines used to power construction equipment), mobile vehicles used to support construction, diesel-fired engines to support power generation, portable equipment, and support systems such as construction camps. Typical non-road engines, portable equipment, and mobile sources include:

- Surface operations, including excavators, trenchers, graders, scrapers, and compactors, which are used to build roads, structure foundations, laydown areas, and temporary surfaces;
- Construction equipment, including cranes, loaders, forklifts, pile drivers, and aerial lifts;
- Support equipment engines, including pumps, compressors, electric power generators, saws, and welders; and
- On-road support vehicles and trucks, including construction and use of access roads.

Construction of each Project facility and the pipeline would include the installation of a construction camp to house employees near the Project site. The camp would provide a full range of services related to maintaining a construction crew, including sleeping quarters, a dining hall, personnel comfort features, and other services to support construction. Camp operations would require several combustion sources,

⁶ Note, the schedule provided in Appendix C is subject to change..

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including power generators, waste incinerators, and space heating operations. Camp operation would also provide urban-style commuter buses to transport crew members between camps and construction sites.

Estimated combustion emissions are based on the equipment design (e.g., horsepower), projected fuel use or hours of operation, fuel type, and an average load factor for equipment operation from available emissions databases. Key emission factors were based on the following:

- Vendor-specific emission factors, where available;
- EPA diesel engine “Tier” standards in 40 C.F.R. Part 89 and Part 1039;
- EPA (2009) emission factors for non-road equipment operating in Alaska;
- EPA (2014b) MOVES2014 data for on-road vehicles;
- EPA (1995) AP-42 emission factors for internal and external combustion equipment; and
- Specific emission factors for marine sources, locomotives, aircraft, and other equipment.

Operational data for equipment and other construction activities, including a listing of equipment, horsepower, and hours of operation, were used to estimate the combustion emissions in Appendix C. Emissions from construction camp electric power generators and waste incinerators are estimated based on expected peak personnel at each camp. Generally, however, engine horsepower ratings for specific construction equipment are estimated from typical equipment.

Open burning of brush cleared from the construction right-of-way would generate combustion emissions. Open burning activity levels will be determined when construction contractors are selected.

9.2.3.1.1.2 Non-Combustion Point Sources

Construction may also include non-combustion emissions, such as vented vapors from tanks. Estimates of these emissions are included in Appendix C.

9.2.3.1.1.3 Fugitive Emissions

Civil construction leads to fugitive dust and particulate matter emissions from a wide array of activities. Clearing, grubbing, site preparation, excavation, drilling and blasting, soil handling, storage piles, construction materials handling, vehicular traffic on paved or unpaved roads, and other activities emit fugitive dust. Emission calculations for fugitive dust are based on commonly accepted methods, including the EPA’s AP-42, which often include site-specific parameters such as soil moisture, silt content, exposed acreage, wind speed, and frequency of precipitation. Activity levels are derived from estimates of parameters, such as vehicle weight, vehicle speed, volumes handled, and hours of operation. Additionally, fugitives may result from activities that emit organic compounds, such as solvent application, coatings, and painting during construction. Except for emission from storage piles, fugitive emissions from construction activities are transient in nature and likely to occur at any one location for a few hours within a single day.

Estimated emissions are provided in Appendix C.

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9.2.3.2 Liquefaction Facility

Construction of the Liquefaction Facility would occur on an approximate 900-acre site located near Nikiski, and would include construction of facilities for LNG production, storage, transfer (all considered the LNG Plant), and construction of a MOF and carrier loading facilities at the Marine Terminal. Construction would take place over an eight-year period and include construction equipment both on the Project site and within Cook Inlet waters. A construction camp for workers would be operated during construction. See Resource Report No. 1 for further details on Liquefaction Facility construction. See Section 9.2.3.1 for a general description of the methodology for calculating construction emissions.

9.2.3.2.1 LNG Plant Construction Emissions

Construction of the LNG Plant and adjacent Marine Terminal is planned for an eight-year period with the total annual emissions for each of those years summarized in Table 9.2.3-1. See Resource Report No. 1 for additional details regarding construction activities. Construction activities would begin with site clearing and stabilization, and include roadway construction, installation of a worker camp, and operating specific project construction equipment noted earlier in this report. See Appendix C for further details on construction emissions, including limitations in data.

TABLE 9.2.3-1 Total Annual Construction Emissions for the Liquefaction Facility and Marine Terminal (Combined)							
Project Construction Year	Tons/Year						Data in Metric Tonnes CO ₂ e/Year
	VOC	NO _x	CO	PM ₁₀	PM _{2.5}	SO ₂	GHG
2	19	366	60	649	76	6	28,534
3	29	637	80	483	62	17	46,077
4	106	1,260	705	2,555	285	27	158,307
5	125	836	1,047	4,701	503	15	170,477
6	97	293	1,004	4,509	478	8	83,941
7	76	224	774	4,227	446	7	64,595
8	43	157	435	3,522	368	4	42,951
9	33	110	396	2,120	222	3	27,043
TOTAL	528	3,883	4,501	22,766	2,440	87	621,925

9.2.3.2.2 Marine Terminal Construction Emissions

Construction of the Marine Terminal adjacent to the LNG site would include the installation of various in-water structures related to the Marine Terminal operations. Many construction activities would take place from barges and tugs, and include cranes, loaders, pile drivers, and support vehicles and operations. Support equipment includes power generators and compressors and haul trucks during construction.

Construction of the Marine Terminal is planned for a two-year period beginning in Year 2 of the Liquefaction Facility construction schedule. The total annual emissions for each of those years are included in Table 9.2.3-1.

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9.2.3.3 Interdependent Project Facilities

9.2.3.3.1 Pipeline Construction Emissions

9.2.3.3.1.1 Mainline

A description of construction of the Mainline components follows. See Resource Report No. 1 for additional details on pipeline construction. See Section 9.2.3.1 for a general description of the methodology for calculating construction emissions for the pipeline and associated aboveground facilities. See Appendix C for further details on construction emissions, including known current gaps in data.

The Mainline pipeline would be constructed simultaneously in four separate spreads of approximately 200 miles each, over six years. Eight compressor stations, including one combined compressor station and collocated heater station, plus one standalone heater station would be constructed over a three-year period at same time as construction of the Mainline. The location of each station is identified in Table 9.2.3-2. Due to their proximity to Mainline pipeline construction, each station's emissions were included in the emissions with the associated construction spread at that location. Actual station construction would occur using three separate pipeline facility construction contractors operating independently from Mainline spread contractors.

TABLE 9.2.3-2 Compressor and Heater Station Locations for Mainline Pipeline			
Compressor or Heater Station	MP	Pipeline Facility Construction Contractor (CC)	Mainline Spread
Sagwon Compressor Station	75.97	CC1	1
Galbraith Lake Compressor Station	148.51	CC1	1
Coldfoot Compressor Station	240.10	CC1	2
Ray River Compressor Station	332.64	CC2	2
Minto Compressor Station	421.55	CC2	3
Healy Compressor Station	517.62	CC2	3
Honolulu Creek Compressor Station	597.35	CC3	3/4
Rabideux Creek Compressor Station	675.23	CC3	4
Theodore River Heater Station	749.11	CC3	4

Pipeline construction for all four spreads would begin in the first year following authorization. The depictions of the areas of the separate spreads are provided in Resource Report No. 1. Emissions from marine construction of the pipeline section crossing Cook Inlet are included in Spread 4.

Table 9.2.3-3 lists the estimated construction emissions for each spread for each of the six years of planned construction. Each spread covers a distance of approximately 200 miles; as such, the emissions are spread over 200 miles instead of being concentrated. To illustrate the spread/distribution of construction over time, Figure 9.2.3-1 provides the total annual PM₁₀ construction emissions for each Mainline spread, and the data depict the comparative level of construction activity for each Mainline spread for each year of construction. Data include fugitive and equipment PM₁₀ emissions. The highest yearly emissions for each spread corresponds with the highest level of construction activity. For example,

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construction activities and emissions for Spread 3 and 4 peak in Years 3 and 4, respectively. Combined PM₁₀ emissions from all spreads peaks in Year 5.

TABLE 9.2.3-3								
Total Annual Construction Emissions for the Mainline Spreads								
Data in ton/year								Data in Metric Tonnes CO ₂ e/year
Project Construction Year		VOC	NOx	CO	PM ₁₀	PM _{2.5}	SO ₂	GHG
	Spread							
2	1	8	43	44	273	33	1	12,212
	2	15	95	110	451	85	3	26,782
	3	12	80	63	417	53	1	21,664
	4	11	56	63	321	40	1	15,327
	Total	46	274	280	1,462	211	6	75,985
3	1	17	118	107	757	120	2	37,971
	2	21	139	194	710	143	4	43,885
	3	26	164	148	1,469	181	2	53,448
	4	14	76	80	542	64	2	21,130
	Total	78	497	529	3,478	508	10	156,434
4	1	19	139	130	678	104	3	38,658
	2	14	117	113	401	82	3	26,041
	3	21	125	110	694	82	3	33,030
	4	39	386	187	1,498	173	7	74,543
	Total	93	767	540	3,271	441	16	172,272
5	1	33	236	176	1,911	243	5	68,321
	2	35	253	196	1,229	167	5	69,744
	3	36	244	179	1,518	183	5	68,158
	4	208	5,001	521	1,104	185	150	261,141
	Total	312	5,734	1,072	5,762	778	165	467,364
6	1	24	212	117	1,936	229	3	57,717
	2	20	168	87	953	118	2	46,861
	3	15	125	74	863	105	2	31,419
	4	19	237	68	862	95	5	36,487
	Total	78	742	346	4,614	547	12	172,484
7	1	4	27	16	275	29	0	8,994
	2	2	11	4	87	9	0	3,201
	3	2	7	9	1	1	0	2,958
	4	1	5	2	31	3	0	1,463
	Total	9	50	31	394	42	0	16,616
Spread								
All	1	105	775	590	5,830	758	14	223,873
	2	107	783	704	3,831	604	17	216,514
	3	112	745	583	4,962	605	13	210,676
	4	292	5,761	921	4,358	560	165	410,092

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TABLE 9.2.3-3 Total Annual Construction Emissions for the Mainline Spreads								
Data in ton/year								Data in Metric Tonnes CO ₂ e/year
Project Construction Year		VOC	NO _x	CO	PM ₁₀	PM _{2.5}	SO ₂	GHG
	Total	6,16	8,064	2,798	18,981	2,527	209	1,061,155

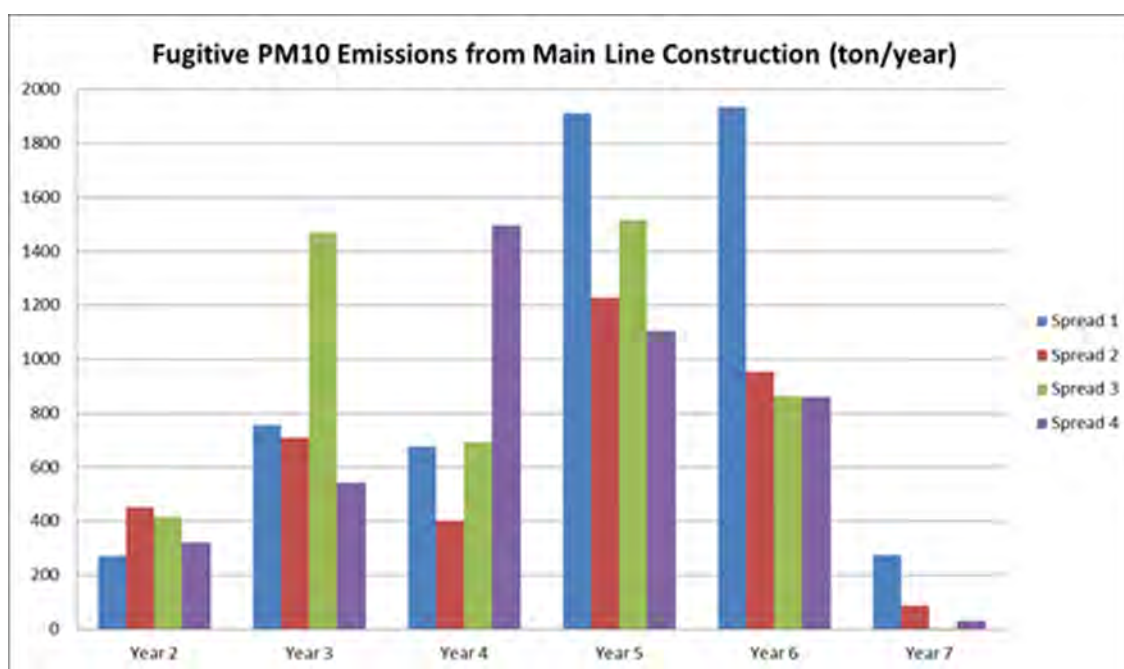


FIGURE 9.2.3-1 Total Annual PM₁₀ Construction Emissions for the Mainline Spreads

9.2.3.3.1.2 Prudhoe Bay Gas Transmission Line (PBTL)

The methodologies for estimating construction emissions from the PBTL are identical to those of the Mainline, including both the available and unavailable data. See Resource Report No. 1 and Section 9.2.3.1 for more details. Supporting documentation is provided in Appendix C.

As noted in Resource Report No. 1, the PBTL would be constructed during the winter. Because there are no trees or brush on the PBTL corridor, there would be no open burning. Emissions from construction of this line would occur within a one- to two-year period, and would not involve a separate construction camp.

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Table 9.2.3-4 provides a summary of the total annual emissions of criteria air pollutants and GHGs for construction of the PBTL. Due to its proximity, PBTL construction emissions are also included in the total GTP construction emissions.

TABLE 9.2.3-4 Total Annual Construction Emissions for the Prudhoe Bay Gas Transmission Line							
Project Construction Year	tons/year						Metric Tonnes CO ₂ e/year
	VOC	NO _x	CO	PM ₁₀	PM _{2.5}	SO ₂	GHG
2	0.0	0.1	0.0	2.1	0.2	0.0	11
3	0.5	4.0	1.9	11.4	2.0	0.0	940
TOTAL	0.5	4.1	1.9	13.5	2.2	0	951

9.2.3.3.1.3 Point Thomson Gas Transmission Line (PTTL)

The methodologies for estimating construction emissions from the PTTL are identical to those of the Mainline, including both the available and unavailable data. See Resource Report No. 1 and Section 9.2.3.1 for more details. Supporting documentation is provided in Appendix C.

As noted in Resource Report No. 1, the PTTL would be constructed during the winter. Because there are no trees and limited brush on the PTTL corridor, there would be no open burning. Emissions from construction of this line occur within a two-year period, beginning in Year 3 and completing in Year 4, and do not involve a separate construction camp. Pipeline construction would occur over two spreads.

Table 9.2.3-5 provides a summary of the total annual emissions of criteria air pollutants and GHGs for construction of the PTTL.

TABLE 9.2.3-5 Total Annual Construction Emissions for the Point Thomson Gas Transmission Line (PTTL)							
Project Construction Year	tons/year						Metric Tonnes CO ₂ e/year
	VOC	NO _x	CO	PM ₁₀	PM _{2.5}	SO ₂	GHG
3	9	62	56	395	49	1	15,279
4	15	56	87	374	52	2	21,877
5	0	0	0	0	0	0	0
6	0	2	1	24	2	0	352
TOTAL	24	120	144	793	103	3	37,508

9.2.3.3.2 Gas Treatment Plant (GTP) Construction Emissions

The GTP would be constructed at Prudhoe Bay on the North Slope near the Beaufort Sea coast. In addition to the GTP facilities, construction would include installation of improvements at West Dock to support marine sealift operations, module staging area, haul roads from West Dock to the GTP site,

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quarry operations, installation of several support pipelines within the PBU, custody transfer facilities, and appurtenant support facilities (e.g., electrical interconnections). Construction activities would take place over nine years, beginning in Year 1 of the Project construction schedule. See Resource Report No. 1 for further details on GTP construction. See Section 9.2.3.1 for a general description of the methodology for calculating construction emissions. See Appendix C for further details on construction emissions, including gaps in data.

Table 9.2.3-6 provides a summary of the total annual emissions of criteria air pollutants and GHGs for construction of the GTP and appurtenant facilities, including the PBTL.

TABLE 9.2.3-6 Total Annual Construction Emissions for the Gas Treatment Plant (GTP)							
Project Construction Year	tons/year						Metric Tonnes CO ₂ e/year
	VOC	NOx	CO	PM ₁₀	PM _{2.5}	SO ₂	GHG
1	3	29	20	140	15	0	6,897
2	17	147	141	683	137	3	50,110
3	21	244	184	597	117	7	49,861
4	18	217	168	515	73	6	45,462
5	22	245	223	572	71	8	58,961
6	23	241	234	565	70	8	61,684
7	21	227	198	604	72	6	55,536
8	14	187	93	537	64	6	32,979
9	4	28	22	247	26	0	11,475
TOTAL	143	1,565	1,283	4,460	645	44	372,965

9.2.3.4 Non-jurisdictional Facilities

Construction emissions from the PTU Gas Expansion project and PBU MGS project would be similar to GTP, PBTL, and PTTL project elements based on the following:

- North Slope construction methods for logistics and winter/summer timing of activities;
- Use of granular pads for infrastructure components;
- Aboveground pipeline design and installation methods;
- Use of modular facilities that are fabricated elsewhere; and
- Use of drilling equipment and procedures adapted to North Slope conditions.

The PTU Gas Expansion is expected to begin construction in Year 3 and with construction completed in Year 7. PTU drilling to support the Project would begin in Year 5 and would be completed in Year 8. For the PBU MGS project, construction would begin in Year 2 and would be completed in Year 6. Drilling at the PBU to support the Project would begin in Year 6 and be completed in Year 10.

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Kenai Spur Highway relocation project construction emissions would be similar to site preparation, granular material source development, and road construction elements for the Liquefaction Facility and site clearing construction elements of the Mainline based on the following:

- Kenai and Nikiski area construction methods and logistics based on vegetation, soil, and groundwater conditions;
- Use of local area material sources; and
- Typical paved road design and construction methods for classified fill, compaction, and paving.

Construction to relocate the Kenai Spur Highway would begin in Year 1 and would be complete in two construction seasons.

Table 9.2.3-7 provides a summary of the total annual emissions of criteria air pollutants and GHGs for construction of the non-jurisdictional facilities, including the PTU Expansion project, PBU MGS project, and Kenai Spur Highway relocation. These emissions include drilling at the PTU and PBU. See Appendix G for further details.

TABLE 9.2.3-7 Total Annual Construction and Drilling Emissions for Non-Jurisdictional Facilities							
Project Construction Year	tons/year						Metric Tonnes CO ₂ e/year
	VOC	NOx	CO	PM ₁₀	PM _{2.5}	SO ₂	GHG
1	1	9	6	8	2	0	1,384
2	4	26	30	105	13	0	7,490
3	363	911	1,450	274	134	2	73,827
4	720	1,732	2,864	558	267	3	139,301
5	949	3,214	3,525	589	306	76	310,684
6	1,007	3,749	3,679	541	312	76	358,659
7	1,006	4,461	3,669	312	288	76	355,720
8	176	1,619	501	47	35	37	137,732
9	60	545	165	13	13	1	50,859
10	60	545	165	13	13	1	50,859
TOTAL	4,347	16,811	16,054	2,460	1,382	271	1,486,513

9.2.4 Applicable Air Quality Regulatory Requirements – Construction

Air quality regulations, both federal and state, address some aspects of the proposed construction activities. Table 9.2.4-1 lists potentially applicable federal regulations under Title 40 of the C.F.R. The cited regulations may apply directly to some construction equipment or activities.

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TABLE 9.2.4-1 Federal Air Quality Regulations Potentially Applying to the Project – Construction		
Citation/Part of 40 C.F.R.	Title	Description
50	NAAQS	Modeling and any monitoring must comply with NAAQS.
51 Appendix W	Guideline on Air Quality Modeling	Dispersion modeling in support of permit applications must comply with this regulation.
58 Appendix E	Air Quality Monitoring	Applies for stationary sources that submit ambient air monitoring data in support of applications
60 Subpart A	General Provisions for New Source Performance Standards (NSPS)	Includes general notifications, recordkeeping, reporting, and sampling requirements for affected units
60 Subpart Db	NSPS for boilers and heaters > 100 MMBtu/hr	Regulates NO _x , SO ₂ , PM emissions from boilers and heaters from stationary sources
60 Subpart Dc	NSPS for boilers and heaters > 10 MMBtu/hr	Standards for small boilers, generally regulating SO ₂ and PM emissions from oil (and solid fuel) fired units.
60 Subpart Kb	NSPS for Tanks <75 m ³	Can apply to tanks storing volatile organic liquids
60 Subpart OOO	NSPS for Non-metallic mineral processing plants	Applies to crushed stone, and sand and gravel processing plants above thresholds with crushers or grinding mills
60 Subpart IIII	NSPS for Compression Ignition Engines	Emissions limits, monitoring, testing requirements for diesel-fired engines based on use, horsepower, and engine sizes
60 Subpart JJJJ	NSPS for Spark Ignition Engines	Emissions limits, monitoring, testing requirements for spark ignition natural gas-fired engines based on use, horsepower, and engine sizes
68	Chemical Accident Prevention	Applies to stationary sources that have more than the threshold quantity of a regulated toxic or flammable substance
63 Subpart ZZZZ	National Emission Standards for Hazardous Air Pollutants (NESHAPs) for stationary engines	Applies to reciprocating internal combustion engines (RICE), including generators, emergency generators, firewater pumps, etc. Generally excluded if complying with NSPS Subparts IIII or JJJJ.
63 Subpart CCCCCC	NESHAPs for Gasoline Dispensing Facilities	Applies to an onsite gasoline dispensing facility, with requirements based on monthly throughput.
80 Subpart I	Emission Control Act (ECA) Marine Fuel Standards	May apply to end-users of marine fuel
82	Stratospheric Ozone Protection	Applies to facilities with listed refrigerants, to manage and control emissions or releases from those units
89	Non-road compression ignition engines	Applies to pre-2014 non-road compression-ignition engines, including portable units
91	Marine spark-ignition engines	May apply to specific marine spark-ignition engines.
93 Subpart B	General Conformity	May apply to construction activities within the Fairbanks PM _{2.5} nonattainment area
94	Marine compression-ignition engines	May apply to specific marine compression-ignition engines.
98 Subparts A and C	Mandatory GHG reporting rule	Sources with > 25,000 metric tons/year of CO ₂ e emissions must calculate and submit annual reports of GHG emissions.
1042	Marine compression-ignition engines	May apply to certain end-users of marine compression-ignition engines
1043	Control of Emissions under Marine Pollution Protocol (MARPOL)	Controls NO _x , SO ₂ , and PM emissions from marine vessels subject to MARPOL Protocol.

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Table 9.2.4-2 provides a listing and brief description of the potentially applicable Alaska air quality regulations in Title 18 of the AAC.

TABLE 9.2.4-2 Alaska Air Quality Regulations Potentially Applying to the Project – Construction		
Citation to 18 AAC 50	Title	Description
50.010	Ambient air quality	Facility must be designed and permitted to operate in compliance with ambient air quality standards
50.020	PSD Baseline dates and maximum allowable increases	Facility must be designed and permitted to operate in compliance with applicable PSD increments. Affects permitting of major sources (LNG and GTP, based on preliminary information)
50.025	Visibility and other special protection areas	Establishes visibility protections for three areas, including (1) Mt. Deborah and the Alaska Range East, as viewed from approximately the Savage River Campground area, (2) Mt. McKinley, Alaska range, and Interior Lowlands as viewed from the vicinity of Wonder Lake, and (3) geographic areas classified as Class I under 18 AAC 50.15(c). This last group is also an area with federally enforceable visibility protection, but this provision allows ADEC to interpret and regulate visibility impacts under its own rules.
50.035 (a) (1) and (2)	Documents adopted by reference	Adopts the (1) ADEC <i>In situ Burning Guidelines for Alaska, Revision 1, revised August 2008</i> and (2) <i>Workbook for Plume Visual Impact Screening and Analysis (Revised)</i> EPA 454/R-92-023, October 1992 as a means of addressing visibility impacts.
50.040 (a)	New Source Performance Standards	Adopts the Federal New Source Performance Standards, including Subpart A general provisions, Subpart IIII for compression ignition reciprocating internal combustion engine, Subpart JJJJ for spark ignition reciprocating internal combustion engines, and subpart KKKK for stationary combustion turbines.
50.040(c)	National Emission Standards for Hazardous Air Pollutants	Adopts the Federal National Emission Standards for Hazardous Air Pollutants, including Subpart ZZZZ for stationary reciprocating internal combustion engines.
50.045 (d)	Prohibitions.	A person who causes or permits bulk materials to be handled, transported, or stored, or who engages in any industrial activity or construction project shall take reasonable precautions to prevent particulate matter from being emitted into the ambient air. No specific permitting or approval for compliance is required; however, the agency may take action if this provision is violated, particularly in response to a complaint by the general public.
50.050	Incinerator emission standards.	Requires opacity to be 20 percent or less averaged over any six consecutive minutes. No limit exists for particulate matter emissions for incinerators that have a rated capacity less than 1,000 pounds per hour. Project design indicates that no incinerators will exceed that design threshold, but if rated capacity is above that level, the PM emission standards would apply.
50.055	Industrial Processes and fuel burning equipment.	This rule limits visible emissions from industrial process or fuel-burning equipment to 20 percent or less for any consecutive six-minute period. Particulate matter emissions from fuel-burning equipment also must comply with grain loading standards in § (b) of the regulation. Sulfur compound emissions from an industrial process or fuel-burning equipment may not exceed 500 ppm averaged over three hours.

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TABLE 9.2.4-2 Alaska Air Quality Regulations Potentially Applying to the Project – Construction		
Citation to 18 AAC 50	Title	Description
50.065	Open burning	The rule specifies requirements for open burning standards. The regulation includes an array of requirements, including minimizing emissions, prohibiting combustion of toxic compounds, and avoidance of open burning during periods of adverse dispersion, as well as provisions for dealing with complaints. When construction contractors are selected, the Open Burning Plan for the Project would address the requirements of this regulation.
50.070	Marine Vessel visible emission standards	Establishes marine vessel visible emission standards and would apply to marine vessels that are used in support of construction both of the pipeline across Cook Inlet and of the LNG terminal facilities. Specific visibility standards apply to these vessels.
50.080	Ice fog standards	Allows ADEC to require a permit to reduce water vapor emissions for fuel burning equipment or an incinerator in areas of potential ice fog
50.100	Nonroad engines	Specifies that the emissions from non-road engines (heavy equipment, portable generators, and any engines that are temporary) are not included when determining the classification of a stationary source or modification for a permit
50.110	Air pollution prohibited	ADEC can restrict emissions which may be injurious to health, welfare, property or unreasonably interfere with the enjoyment of life or property. Construction activities that may cause excessive dust, particularly near residences or sensitive receptors, may be curtailed under this regulation if a complaint is received and ADEC considers the impacts to be within these adverse determinations.
50.215	Ambient air quality analysis methods	Provides methods for analyzing (or modeling) ambient air quality impacts for permitting
50.215 (b)(2)(A)	Ambient air quality analysis methods	Excludes temporary construction emissions from the need to predict ambient air quality compliance with PSD increments
50.220	Test methods	References test methods for demonstrating compliance with emission limits
50.225	Owner requested limits	Operators and owners can request emission limits that limit applicability of other air quality regulations
50.235	Unavoidable emergencies	Establishes rules for reporting and responding to emergencies related to air pollution
50.240	Excess emissions	Provides requirements for reporting excess emissions including startup and shutdown.
50.245 and 50.246	Air Quality episodes	Allows ADEC to declare an air quality episode based on actual or potential impacts, and subsequently request voluntary reductions in emissions from stationary sources.
50.326	Title V operating permits	Sources with emissions of 100 ton/year or greater of any regulated criteria pollutant (not GHG) must obtain an operating permit, renewable on a five-year basis, and when new applicable requirements affect the source.
50.345 50.346	Construction minor and operating permits standard permit conditions	Compliance requirements (standard conditions) for Title V operating and minor sources permits and for modifications to existing stationary sources. Includes requirements for notifications, document submittals, and inventory reporting.
50.400 - 50.499	User Fees	Establishes fee schedules for permits and permit renewals.
50.502	Minor construction permits	Specifies provisions for requiring a minor source construction

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TABLE 9.2.4-2 Alaska Air Quality Regulations Potentially Applying to the Project – Construction		
Citation to 18 AAC 50	Title	Description
		permit for certain activity, based on the potential emissions from a stationary source or modification. Certain components of the construction activity may qualify as a stationary source depending on the duration of activity at a specific location. Minor permits must be obtained for the following potential activities under §(b) of this regulation: (1) An asphalt plant with a rated capacity of at least 5 tons/hour of product (2) A rock crusher with a rated capacity of 5 tons/hour (3) One or more incinerators with a cumulative rated capacity of 1,000 lbs./hour or more
50.508	Minor permits requested by owner or operator	Owner or operator can establish enforceable emission limits in a permit to avoid applicability of specific regulations.
50.540	Minor Permits	A minor source construction permit is required based on potential emissions.
50.544	Minor permits: content	Requires permit conditions for minor sources.
50.990	Definitions	Includes specific definitions for activity regulated under state air quality rules. Includes (107) temporary construction activity is defined as a construction activity that is 24 months or less (including intervening periods of inactivity).

9.2.5 Air Quality Emissions and Potential Impacts from Operations Sources

Federal and state air quality regulations govern emissions of criteria air pollutants, hazardous air pollutants (HAPs), state-only specified pollutants (ammonia), VOCs in general, ozone-depleting substances, and GHGs in certain cases. Under its New Source Review (NSR) and Title V operating permit programs, ADEC issues construction and/or operating permits to new, modified, and existing stationary sources or facilities. These permits would establish terms and conditions for compliance with air quality standards, require compliance with source-specific emission standards, and provide a monitoring, recordkeeping, and reporting mechanism to verify continued compliance. Specific air permitting and regulatory requirements are discussed in Section 9.2.6. Compliance with these regulations requires, among other things, detailed Project data on operations and emissions, as well as analyses of potential ambient air quality impacts and impacts on other air quality related values.

The assessments provided in this section evaluate air quality emissions and impacts from Project operations and include emissions from facility equipment and marine vessels in the immediate vicinity of the berths. Specifically, marine operations occurring within 1,640 feet (500 meters) of the berths were modeled, which includes: loading and hoteling operations for LNGCs while in port, maneuvering of the carriers into and out of port, and maneuvering and idling of marine tugs while assisting the carriers. Support equipment sources, such as onsite vehicles, are not included in modeling impacts because they are negligible.

Following applicable regulatory guidance, dispersion modeling ambient air quality and AQRV impacts for the Project are assessed in a matrix presented as:

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- Near-field analyses – impacts within 50 kilometers of a facility (the accepted limit of EPA’s AERMOD air quality dispersion model);
- Far-field analyses – impacts more than 50 kilometers up to 300 kilometers of a facility (the accepted range of EPA’s CALPUFF model is out to 300 kilometers);
- Criteria pollutant analyses – compliance with applicable NAAQS, AAAQS, and PSD Increments; and
- Air quality related values analyses – evaluation of AQRVs at Class I and designated Sensitive Class II areas (see Sections 9.2.2.3.3 and 9.2.2.3.4).

Criteria pollutant impacts are assessed by following established regulatory modeling procedures to estimate maximum facility impacts and, if applicable, cumulative impacts from other nearby facilities. These modeled impacts are either (1) added to measured ambient air background concentrations to determine compliance with the NAAQS and AAAQS, or (2) compared to the PSD increments. These comparisons follow established, complex statistical analyses for ascertaining compliance.

AQRVs are evaluated using metrics established by the FLMs. Unlike the NAAQS, AAAQS, and PSD increments, there are no strict pass/fail criteria for AQRVs. Rather, there are screening levels below which no concern exists. If modeling analyses yield results above the screening criteria, further investigation may be warranted on a case-by-case basis in consultation with the relevant FLM.

Complete details on each of these aspects of the air quality analyses are provided in Appendices D, E, and F, respectively for the Liquefaction Facility, Mainline Compressor and Heater Stations, and GTP.

9.2.5.1 Liquefaction Facility

9.2.5.1.1 LNG Plant Emissions

Natural gas delivered via the Mainline would flow from the LNG Plant receipt point (plant inlet flange) through a pressure regulating station and undergo flow control, separation, and filtration. A detailed process description is provided in Resource Report No. 1. LNG would then be transferred to the LNG storage tanks for subsequent delivery to LNGCs. The processing operations would include the following general sources of emissions:

- Approximately 550 megawatts (MW) of natural gas turbine compressor capacity. These turbines are expected to be equipped with lean premix air/fuel controls designed to reduce NO_x and CO emissions to nominally 10 ppm, respectively, at 15 percent O₂. Precise emissions performance data was genericized as potentially commercially sensitive information, and the use of installed capacity is a better reflection of potential impacts;
- Natural gas power generation turbines with potential for supplemental firing and heat recovery steam generators. Total power generation capacity will be approximately 115 MW;

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- A gas-fired thermal oxidizer for controlling breathing and working losses from the C5+ storage tank and the C5+ loading facilities;
- One reciprocating internal combustion engine for an emergency firewater pump, and one for auxiliary air compression;
- Four flares, including ground flares and elevated low pressure flare for emergency and routine control of excess gas; and
- At least one liquid-fired auxiliary diesel-generator set of docked LNGCs handling the hotel load, sea water, and freshwater cooling pumps, as well as ballast pumps.

Emissions estimates are based on Project design data for equipment and operations. Key input data are the total firing rate for turbines, hours of operation, projected load, projected gas heat content, and projected use of diesel fired engines, including air compression and support for LNGC hoteling and running equipment when at berth. Emission factors are derived from standard databases or vendor data from typical sources such as turbines, heaters, and engines. Vendor data that are used are considered representative of emissions, but should not be treated as a representation of equipment to be used in the final design. Details of the equipment design, fuel use, hours of operation, emission factors, projected load factors, and other operational considerations are provided in Appendix D.

Fugitive emissions of volatile organic compounds and methane would be emitted from piping components and connectors throughout the LNG Plant. Emissions are estimated from component counts (valves, flanges, pumps, compressors, etc.) and EPA and industry emission factors.

Based on the design that is available, short-term and annual emissions from operation of this equipment, including fugitive emissions and potential HAPs, are provided in Table 9.2.5-1. Emission calculations are included in Appendix D. Hourly and short-term emissions are based on worst-case assumptions regarding performance and maximum facility design capabilities, using vendor-supplied emission data, where available, or standard emission factors. Emissions are for normal operation of the LNG Plant and include mobile and non-road emissions associated with operation, but do not include flaring except for pilot/purge.

TABLE 9.2.5-1 Total Emissions from LNG Plant Operations		
Pollutant	Potential to Emit (pounds per hour)	Potential to Emit (tons per year)
Nitrogen Oxides (NO _x)	363	1,181
Carbon Monoxide (CO)	741	1,734
Volatile Organic Compounds (VOCs)	609	216
Particulate Matter (PM ₁₀)	91	260
Particulate Matter (PM _{2.5})	91	260
Sulfur Dioxide (SO ₂)	24.7	90
Largest Individual Hazardous Air Pollutant (Formaldehyde) ^c	7.0	25.8
Total Hazardous Air Pollutants (HAPs)	11.5	37.7

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TABLE 9.2.5-1 Total Emissions from LNG Plant Operations		
Pollutant	Potential to Emit (pounds per hour)	Potential to Emit (tons per year)
Total Greenhouse Gas (GHG) Emissions (CO ₂ e) ^{a,b}	Not Applicable	3,850,732
^a Annual emissions of GHGs are reported in metric tons (tonnes) per year. ^b The total GHG emissions are calculated as CO₂ equivalent (CO₂e) emissions, i.e., the sum of individual GHGs with the annual tons of each gas multiplied by its Global Warming Potential (GWP) relative to CO₂. CH₄ is converted to CO₂e by multiplying its emissions by the GWP of 25, and N₂O is converted to CO₂e by multiplying its emissions by the GWP of 298. ^c Product of incomplete combustion		

9.2.5.1.2 LNG Carrier Emissions

Marine vessels (both LNGCs and support vessels) would be used to transport LNG from the Marine Terminal in Cook Inlet to various international destinations. On March 26, 2010, the International Maritime Organization (IMO) amended the International Convention for the Prevention of Pollution from Ships (Marine Pollution Protocol [MARPOL]) designating specific portions of U.S., Canadian, and French waters as an Emission Control Area (ECA), including the waters of Cook Inlet and the Nikiski vicinity. Vessels subject to the rule and operating in ECAs must use fuel (typically marine diesel oil) with sulfur no greater than 0.1 percent and must use engines on new or reconstructed ships that meet Tier III NO_x standards. See 40 C.F.R. 1043.60 for details.

In compliance with 40 C.F.R. 1043, vessels subject to the rule operating in U.S. ECA waters are generally required to obtain from EPA an Engine International Air Pollution Prevention (EIAPP) Certificate or otherwise provide evidence of conformance with MARPOL Annex VI. Compliance requirements for various potentially applicable regulations could include engine design data, certifications, date of engine manufacture, emissions test data, and in-use fuel specifications, including sulfur limits in fuel. Tugs used in marine operations must comply with rules distinct from the IMO/MARPOL rules. The rules applicable to tugs are administered by EPA and require engines to meet tier standards based on year of manufacture. In addition, the tugs using diesel engines must fuel those engines with ultra-low sulfur diesel containing 15 ppm sulfur or less.

Emissions estimates for marine operations are provided in Appendix D for tugs and LNGCs both in transit through Alaska waters and in dock. Consistent with guidance from FERC, marine operations transit emissions are limited to those emitted while a vessel is within “state waters.” The Project design is for production up to 20 million metric tonnes per year of LNG shipping (44 million cubic meters per year for average density LNG). LNG carriers are assumed to hold 216,000 cubic meters, resulting in about 204 calls per year, with a mix of 98 percent of the units driven by combustion engines and two percent by steam turbines. Five percent of each group arrives in a “warm” status and would have to be cooled down prior to loading. Emissions were calculated for this mix of carriers based on 18 hours of LNG loading (including potentially 18 hours of hoteling and running auxiliary machinery) and a total of 16.5 hours in all phases of transit. Four tugs of 90-ton bollard pull capacity would support each carrier arrival and departure at the terminal and one tug would be in standby near the LNGC while the carrier is at berth.

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Total emissions for these operations, including transit, loading, and hoteling, are provided in Table 9.2.5-2. Detailed calculations of LNGC and marine emissions are provided in Appendix D.

TABLE 9.2.5-2 Total Annual Emissions from LNGC and Tug Support Operations (tons per year)	
Pollutant	Total
Nitrogen Oxides (NO _x)	380
Carbon Monoxide (CO)	630
Volatile Organic Compounds (VOCs)	117
Particulate Matter (PM ₁₀)	14.0
Particulate Matter (PM _{2.5})	13.0
Sulfur Dioxide (SO ₂)	1.2
Total Hazardous Air Pollutants (HAPs)	0.3
Total GHG Emissions (CO ₂ e) ^{a,b}	81,248
^a Annual emissions of GHGs are given in metric tons (tonnes) per year. ^b The total GHG emissions are calculated as CO₂ equivalent (CO₂e) emissions, i.e., the sum of individual GHGs with the annual tons of each gas multiplied by its Global Warming Potential (GWP) relative to CO₂. CH₄ is converted to CO₂e by multiplying its emissions by the GWP of 25, and N₂O is converted to CO₂e by multiplying its emissions by the GWP of 298.	

Note that LNGCs, when not loading, and tug emissions are not included in LNG Plant emissions for permit applicability purposes.

9.2.5.1.3 Air Quality Impacts

Air quality impacts from the Liquefaction Facility operation would result from the emissions units identified in the previous section—primarily natural gas-fired compression turbines, power generation turbines, and marine operations. Additionally, the LNG Plant would include a thermal oxidizer to control vent emissions from hydrocarbon tanks, auxiliary and emergency reciprocating internal combustion engines (RICEs), and emergency flares, which will also generate emissions from pilot and purge gas. Impact assessment includes emissions from carriers and tugs within 1,640 feet (500 meters) of the dock that are docking, loading, and hoteling. Consistent with guidance from FERC, carrier transit emissions are included in the total annual emissions expressed in Table 9.2.5-2, but are not modeled.

9.2.5.1.4 Near-Field Analyses – Ambient Air Quality Impacts

To assess near-field air quality impacts, dispersion modeling was conducted using the AERMOD model Version 15181, with AERMAP and AERMET pre-processors, in accordance with EPA's Guideline on Air Quality Models (40 C.F.R. 51 Appendix W) and ADEC's Modeling Review Procedures Manual (ADEC, 2016b). Five years of meteorological data from the Kenai Airport site and upper air data from Anchorage were used in this analysis. This meteorological dataset had been approved by ADEC for previous air permit application modeling requirements in this region. A nested receptor grid was established at the facility fence line and at a 500-foot (152-meter) buffer around the Marine Terminal area. Receptor spacing of 82 feet (25 meters) was established along the fence line out to 656 feet (200 meters) from the fence line, extending through additional grids of 328 feet (100 meters), 820 feet (250

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meters), 1,640 feet (500 meters), 3,280 feet (1,000 meters), and 6,560 feet (2,000 meters) out to 12.4 miles (20 kilometers) from the LNG Plant. Background air quality data were taken from a Project monitoring site that collected data near Nikiski during 2015. A total of one year of existing air quality data were used to characterize background for this analysis. Details of this modeling effort are included in Appendix D.

A formal modeling protocol would be submitted to ADEC for concurrence, then an ambient air quality impact analysis would be completed as part of the air permit application for the Liquefaction Facility. In advance of the formal protocol, a “modeling approach” and draft modeling protocol were circulated to the EPA, FLMs, ADEC, and FERC. Subsequent dialogue and correspondence with these agencies has helped to guide the modeling impact analysis, including AQRV analysis, for Resource Report No. 9.

Based on the Project modeling results detailed in Appendix D, the predicted maximum air quality impacts for criteria air pollutants are summarized in Table 9.2.5-3, along with the NAAQS, and Alaska AAQS. These results are based on emissions from the normal operations of the Liquefaction Facility including marine operations within 500 meters of the dock. In addition to modeling Project sources associated with the Liquefaction Facility, the Appendix D dispersion analysis also addressed the cumulative ambient air quality impacts from the proposed Project and nearby offsite sources (see Appendix L of Resource Report No. 1). The following offsite sources are included in the analysis:

- Tesoro Refinery;
- Existing ConocoPhillips Company Kenai LNG Facility (including ships);
- Tesoro Kenai Pipe Line (KPL) Marine Loading Terminal (including ships);
- Homer Electric Association (HEA) Bernice Lake Power Plant;
- Agrium Kenai Nitrogen Plant and Loading Terminal (including ships) (Agrium); and
- HEA Nikiski Generation Plant.

No other sources were explicitly modeled because they were either not expected to produce a significant concentration gradient in the impact area or were included as part of the background concentration. As shown in Table 9.2.5-3, the modeling results for normal operations of the Liquefaction Facility, when added to the measured background air quality concentrations, demonstrate compliance with the NAAQS and AAAQS. The model-predicted concentrations in Table 9.2.5-4 demonstrate compliance with the increments.

TABLE 9.2.5-3 Air Quality Impact NAAQS/AAAQS Analysis for the LNG Plant and Marine Terminal – Normal Operations						
Air Pollutant	Averaging Period	Model-Predicted (Project-only) Concentration (µg/m ³)	Ambient Background Concentration (µg/m ³)	Total Concentration (µg/m ³)	NAAQS (µg/m ³)	AAAQS (µg/m ³)
Sulfur Dioxide	1-Hour ^a	57.5	5.0	62.5	196	196
	3-Hour ^b	39.6	5.0	44.6	1,300	1,300
	24-Hour ^b	17.1	2.4	19.5	---	365
	Annual ^d	0.11	0.0	0.11	---	80
Carbon	1-Hour ^b	2,721	1,145	3,866	40,000	40,000

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TABLE 9.2.5-3 Air Quality Impact NAAQS/AAQS Analysis for the LNG Plant and Marine Terminal – Normal Operations						
Air Pollutant	Averaging Period	Model-Predicted (Project-only) Concentration (µg/m³)	Ambient Background Concentration (µg/m³)	Total Concentration (µg/m³)	NAAQS (µg/m³)	AAQS (µg/m³)
Monoxide	8-Hour ^b	1,071	1,145	2,216	10,000	10,000
Nitrogen Dioxide	1-Hour ^c	140.1	32.3	172.4	188	188
	Annual ^d	8.4	2.6	11.0	100	100
Particulate Matter less than 10 Microns	24-Hour ^f	5.1	40	45.1	150	150
Particulate Matter less than 2.5 Microns	24-Hour ^e	3.6	12	15.6	35	35
	Annual ^g	0.38	3.7	4.1	12	12

TABLE 9.2.5-4 Increment Analysis for the LNG Plant and Marine Terminal – Normal Operations			
Air Pollutant	Averaging Period	Model-Predicted Concentration (µg/m³)	Class II Increments (µg/m³)
Sulfur Dioxide	1-Hour ^a	NA	NA
	3-Hour ^b	39.6	512
	24-Hour ^b	17.1	91
	Annual ^c	0.11	20
Nitrogen Dioxide	Annual ^c	8.4	25
Particulate Matter less than 10 Microns	24-Hour ^b	5.4	30
	Annual ^c	0.43	17
Particulate Matter less than 2.5 Microns	24-Hour ^b	4.8	9
	Annual ^c	0.43	4
Abbreviations: NA = not applicable µg/m³ = micrograms per cubic meter Notes: ^a Neither EPA nor ADEC have established increment thresholds for 1-hr NO ₂ , 1-hr SO ₂ , 1-hr CO, or 8-hr CO. ^b Value reported is the maximum of the highest-second-high values from each of the five modeled years. ^c Value reported is the maximum annual average concentration for the five-year period.			

Cumulative model-predicted concentrations from the Liquefaction Facility and offsite sources are compared to the NAAQS and AAQS in Table 9.2.5-5 and to the increments in Table 9.2.5-6. All model-predicted impacts are below the applicable standards and increments.

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TABLE 9.2.5-5 Cumulative Air Quality NAAQS/AAAQS Impact Analysis for the LNG Plant and Marine Terminal – Normal Operations						
Air Pollutant	Averaging Period	Model-Predicted Concentration (µg/m³)	Ambient Background Concentration (µg/m³)	Total Concentration (µg/m³)	NAAQS (µg/m³)	AAAQS (µg/m³)
Sulfur Dioxide	1-Hour ^a	63.4	5.0	68.4	196	196
	3-Hour ^b	50.6	5.0	55.6	1,300	1,300
	24-Hour ^b	32.0	2.4	34.4	---	365
	Annual ^d	0.6	0.0	0.6	---	80
Carbon Monoxide	1-Hour ^b	2,721	1,145	3,866	40,000	40,000
	8-Hour ^b	1,071	1,145	2,216	10,000	10,000
Nitrogen Dioxide	1-Hour ^c	149.5	32.3	181.8	188	188
	Annual ^d	20.4	2.6	23.0	100	100
Particulate Matter less than 10 Microns	24-Hour ^f	23.9	40	63.9	150	150
Particulate Matter less than 2.5 Microns	24-Hour ^e	6.4	12	18.4	35	35
	Annual ^d	2.8	3.7	6.5	12	12
µg/m³ = micrograms per cubic meter ^a Value is the 99th percentile of the annual distribution of daily maximum values averaged over the five-year period. ^b Value is the highest, second highest concentration of the values determined for each of the five modeled years. ^c Value is the 98th percentile of the annual distribution of daily maximum values averaged over the five-year period. ^d Value is the maximum annual average concentration for the five-year period. ^e Value reported is the 98th percentile averaged over the five-year period. ^f Value reported is the highest, 6th highest concentration over the five-year period.						

TABLE 9.2.5-6 Cumulative Increment Analysis for the LNG Plant and Marine Terminal – Normal Operations			
Air Pollutant	Averaging Period	Model-Predicted Concentration (µg/m³)	Class II Increments (µg/m³)
Sulfur Dioxide	1-Hour ^a	NA	NA
	3-Hour ^b	39.6	512
	24-Hour ^b	17.5	91
	Annual ^c	0.6	20
Nitrogen Dioxide	Annual ^c	12.5	25
Particulate Matter less than 10 Microns	24-Hour ^b	24.7	30
	Annual ^c	2.7	17
Particulate Matter less than 2.5 Microns	24-Hour ^b	8.7	9

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TABLE 9.2.5-6 Cumulative Increment Analysis for the LNG Plant and Marine Terminal – Normal Operations			
Air Pollutant	Averaging Period	Model-Predicted Concentration (µg/m³)	Class II Increments (µg/m³)
	Annual ^c	1.3	4
Abbreviations: NA = not applicable µg/m³ = micrograms per cubic meter Notes: ^a Neither USEPA nor ADEC have established increment thresholds for 1-hr NO ₂ , 1-hr SO ₂ , 1-hr CO, or 8-hr CO. ^b Value reported is the maximum of the highest-second-high values from each of the five modeled years. ^c Value reported is the maximum annual average concentration for the five-year period.			

9.2.5.1.5 Near-Field Analyses – Air Quality Related Values (AQRVs)

There are no Class I areas within 50 kilometers of the Liquefaction Facility and there is one Sensitive Class II area (see Appendix D, Figure 2-1) Kenai National Wildlife Refuge – Sensitive Class II Area (10 kilometers).

Complete details of the visibility and deposition AQRV analyses at the Kenai NWR are provided in Appendix D.

The model used for Liquefaction Facility near-field visibility analysis was VISCREEN using the Level II assessment methodology. VISCREEN requires emission rates of NO_x and primary particulate, which were based on the Liquefaction Facility emissions in Sections 9.2.5.2.1 and 9.2.5.2.2. Two observer locations were chosen for visibility: (1) the nearest point in the Kenai NWR to the proposed Liquefaction Facility site, which is a distance of about 10 kilometers, and (2) Skilak Lake, a popular visitor destination about 52 kilometers from the Liquefaction Facility. Meteorological conditions were based on an analysis of the same five years of Kenai Airport NWS data (2008–2012) that were used for the ambient air quality modeling. Background visual range was based on the FLAG (2010) for the Tuxedni NWR Class I area. The VISCREEN default ozone background value of 40 parts per billion by volume (ppbv) was used, which is consistent with measurements collected at the DNPP. See Appendix D for more details.

A total of 40 visibility scenarios were modeled including perceptibility (ΔE) and contrast (Cp) for the two observer locations at Kenai NWR with both sky and terrain background. Results for all but three scenarios were below the Class I screening criteria wherein no concern exists. For the three scenarios that were not below the screening criteria, all were for compressor turbine plume scenarios at either the closest wildlife refuge boundary point or at Skilak Lake with perceptibility as the primary issue. These results are still low.

Deposition modeling at Kenai NWR used the CALPUFF model, which is consistent with FLAG (2010) for near-field deposition analyses. CALPUFF deposition modeling is both complex and conservative (see Appendix D for details). The results for Kenai NWR compared to the Class I screening deposition

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analysis thresholds (DATs) are provided in Table 9.2.5-7. As shown in Table 9.2.5-7, the sulfur and nitrogen deposition from the Liquefaction Facility would be above the Class I DATs at Kenai NWR.

TABLE 9.2.5-7 Deposition Modeling Results for Kenai NWR			
Scenario	Pollutant	CALPUFF Model Predicted Impact (kg/ha/yr)	Class I Deposition Analysis Thresholds (kg/ha/yr)
Liquefaction Facility	Sulfur	0.0058	0.005
	Nitrogen	0.031	0.005

9.2.5.1.6 Far-Field Analyses – Ambient Air Quality and AQRVs

Generally ambient air quality impacts decrease with distance from an emission source due to mixing and dilution in the atmosphere. The results for ambient air quality in Section 9.2.5.2.3 demonstrate that there are no issues for the Liquefaction Facility complying with NAAQS, AAAQS, or increments in the near field, and therefore by extension there are no issues in the far field. Thus, the far-field analyses focus on impacts at Class I and Sensitive Class II areas.

Class I and Sensitive Class II areas in the range of 50–300 kilometers of the Liquefaction Facility, with the distances away, are (see Appendix D, Figure 2-1):

- Lake Clark National Park & Preserve – Sensitive Class II Area (50 kilometers);
- Chugach National Forest – Sensitive Class II Area (74 kilometers);
- Tuxedni NWR – Class I Area (86 kilometers);
- Kenai Fjords National Park – Sensitive Class II Area (92 kilometers);
- DNPP – Class I Area (183 kilometers); and
- Kodiak NWR – Sensitive Class II Area (256 kilometers).

Complete details of the ambient air quality, visibility, and deposition analyses at each of the areas is provided in Appendix D.

EPA's CALPUFF model was used to assess impacts at each of these areas. CALPUFF uses a prognostic meteorological input dataset. The most recent available dataset for the domain around the Liquefaction Facility is the three-year (2002–2004) Fifth Generation Penn State/NCAR Mesoscale Model (MM5) dataset developed for the Alaska BART Coalition. This dataset has been used for previous CALPUFF modeling in the Cook Inlet area and has been approved by ADEC for this region. The MM5 modeling domain is a 540-kilometer by 650-kilometer grid centered on Cook Inlet and encompassing each of the Class I and Sensitive Class II areas listed in this section. See Appendix D, Figure 6-1, for a location map.

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For cumulative impact analyses, the far-field modeling included existing sources and reasonably foreseeable development not close enough to the Liquefaction Facility to cause a significant concentration gradient. A total of 23 other facilities were included in the far-field modeling to account for these impacts. See Appendix D, Figure 4-1, for the locations of these facilities.

The NAAQS, AAAQS, and increment modeling results for the six Class I and Sensitive Class II areas listed are all well below the applicable standards. The most sensitive of these are the Class I increment analyses at Tuxedni NWR and the DNPP. These results are provided in Tables 9.2.5-8 and 9.2.5-9, respectively, demonstrating that the Liquefaction Facility would not cause or contribute to a violation of the increments at Alaska Class I areas. The remainder of the results are provided in Appendix D.

TABLE 9.2.5-8 Increment Analysis for the LNG Plant and Marine Terminal – Tuxedni NWR				
Air Pollutant	Averaging Period	Liquefaction Facility Only Model-Predicted Concentration ($\mu\text{g}/\text{m}^3$)	Cumulative Analysis Model-Predicted Concentration ($\mu\text{g}/\text{m}^3$)	Class I Increments ($\mu\text{g}/\text{m}^3$)
Sulfur Dioxide	1-Hour ^a	NA	NA	NA
	3-Hour ^b	0.12	0.64	25
	24-Hour ^b	0.05	0.30	5
	Annual ^c	0.003	0.03	2
Nitrogen Dioxide	Annual ^c	0.02	0.18	2.5
Particulate Matter less than 10 Microns	24-Hour ^b	0.34	1.74	8
	Annual ^c	0.02	0.10	4
Particulate Matter less than 2.5 Microns	24-Hour ^b	0.38	1.78	2
	Annual ^c	0.02	0.10	1
Abbreviations: NA = not applicable $\mu\text{g}/\text{m}^3$ = micrograms per cubic meter Notes: ^a Neither USEPA nor ADEC have established increment thresholds for 1-hr NO ₂ , 1-hr SO ₂ , 1-hr CO, or 8-hr CO. ^b Value reported is the maximum of the highest-second-high values from each of the five modeled years. ^c Value reported is the maximum annual average concentration for the five-year period.				

TABLE 9.2.5-9 Increment Analysis for the LNG Plant and Marine Terminal – DNPP				
Air Pollutant	Averaging Period	Liquefaction Facility Only Model-Predicted Concentration ($\mu\text{g}/\text{m}^3$)	Cumulative Analysis Model-Predicted Concentration ($\mu\text{g}/\text{m}^3$)	Class I Increments ($\mu\text{g}/\text{m}^3$)
Sulfur Dioxide	1-Hour ^a	NA	NA	NA
	3-Hour ^b	0.10	15.5	25
	24-Hour ^b	0.04	4.05	5
	Annual ^c	0.002	0.26	2
Nitrogen Dioxide	Annual ^c	0.02	0.12	2.5

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TABLE 9.2.5-9 Increment Analysis for the LNG Plant and Marine Terminal – DNPP				
Air Pollutant	Averaging Period	Liquefaction Facility Only Model-Predicted Concentration ($\mu\text{g}/\text{m}^3$)	Cumulative Analysis Model-Predicted Concentration ($\mu\text{g}/\text{m}^3$)	Class I Increments ($\mu\text{g}/\text{m}^3$)
Particulate Matter less than 10 Microns	24-Hour ^b	0.31	1.67	8
	Annual ^c	0.01	0.08	4
Particulate Matter less than 2.5 Microns	24-Hour ^b	0.34	1.76	2
	Annual ^c	0.01	0.08	1
Abbreviations: NA = not applicable $\mu\text{g}/\text{m}^3$ = micrograms per cubic meter Notes: ^a Neither USEPA nor ADEC have established increment thresholds for 1-hr NO ₂ , 1-hr SO ₂ , 1-hr CO, or 8-hr CO. ^b Value reported is the maximum of the highest-second-high values from each of the five modeled years. ^c Value reported is the maximum annual average concentration for the five-year period.				

For far-field AQRV analysis, regional haze impacts were modeled at each of the six Class I and Sensitive Class II areas using the CALPUFF model and the same domain and modeling inputs as the far-field ambient air quality impact analyses. See Appendix D for complete details.

Regional haze impacts are estimated based on the change in light extinction. If the predicted change in light extinction due to Project sources is less than 5 percent, there is no concern. Furthermore, if the predicted change in light extinction due to Project and offsite sources is less than 10 percent, there is no concern. If modeled impacts are above either of these thresholds, further investigation may be warranted on a case-by-case basis in consultation with the relevant FLM.

TABLE 9.2.5-10 Regional Haze Results for the LNG Plant and Marine Terminal Only					
Class I/II Area	Year	Number of Days with Extinction Above		8th Highest Change in Extinction (%)	Visibility Extinction Threshold for a Project (%)
		5%	10%		
Tuxedni NWR	2002	2	0	2.9	5.0
	2003	1	0	3.5	5.0
	2004	5	0	4.5	5.0
DNPP	2002	2	0	2.8	5.0
	2003	2	0	3.1	5.0
	2004	3	0	3.7	5.0
Kenai Fjords National Park	2002	0	0	1.6	5.0
	2003	0	0	2.0	5.0
	2004	0	0	1.5	5.0
Chugach National Forest	2002	2	0	2.9	5.0
	2003	0	0	2.8	5.0

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TABLE 9.2.5-10 Regional Haze Results for the LNG Plant and Marine Terminal Only					
Class I/II Area	Year	Number of Days with Extinction Above		8th Highest Change in Extinction (%)	Visibility Extinction Threshold for a Project (%)
		5%	10%		
	2004	1	0	2.9	5.0
Lake Clark National Park	2002	7	0	4.9	5.0
	2003	8	0	5.1	5.0
	2004	13	0	5.3	5.0
Kodiak NWR	2002	0	0	0.5	5.0
	2003	0	0	0.4	5.0
	2004	0	0	0.4	5.0

TABLE 9.2.5-11 Cumulative Regional Haze Results for the LNG Plant and Marine Terminal Plus Offsite Sources					
Class I/II Area	Year	Number of Days with Extinction Above		8th Highest Change in Extinction (%)	Cumulative Visibility Extinction Threshold (%)
		5%	10%		
Tuxedni NWR	2002	144	70	24.5	10.0
	2003	136	67	28.5	10.0
	2004	142	75	25.3	10.0
DNPP	2002	194	100	46.7	10.0
	2003	198	102	53.3	10.0
	2004	208	127	47.8	10.0
Kenai Fjords National Park	2002	35	9	11.3	10.0
	2003	35	8	10.2	10.0
	2004	26	2	7.5	10.0
Chugach National Forest	2002	214	121	34.8	10.0
	2003	220	136	38.2	10.0
	2004	206	113	43.9	10.0
Lake Clark National Park	2002	261	157	40.2	10.0
	2003	243	138	40.3	10.0
	2004	261	153	50.8	10.0
Kodiak NWR	2002	29	10	11.2	10.0
	2003	46	9	10.3	10.0
	2004	32	11	13.2	10.0

Table 9.2.5-10 demonstrates the Liquefaction Facility generally would not contribute to visibility impairments at Class I and Sensitive Class II areas within 300 kilometers. The exception is at Lake Clark National Park where results are slightly above the screening thresholds.

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As for the cumulative impact results presented in Table 9.2.5-11, modeled impacts are above the screening criteria at each of the six Class I and Sensitive Class II areas.

The far-field deposition modeling using CALPUFF followed the same procedure as described for near-field impacts in Section 9.2.5.2.4. Details are provided in Appendix D. Results for the Liquefaction Facility only and cumulative sources are provided in Tables 9.2.5-12 and 9.2.5.13, respectively.

TABLE 9.2.5-12 Deposition Results for the LNG Plant and Marine Terminal Only				
Class I/II Area	Year	Sulfur Predicted Impact (kg/ha/yr)	Nitrogen Predicted Impact (kg/ha/yr)	Class I Deposition Analysis Thresholds (kg/ha/yr)
Tuxedni NWR	3-Year Max	0.0052	0.014	0.005
DNPP	3-Year Max	0.0037	0.014	0.005
Kenai Fjords National Park	3-Year Max	0.0003	0.002	0.005
Chugach National Forest	3-Year Max	0.001	0.0048	0.005
Lake Clark National Park	3-Year Max	0.0059	0.020	0.005
Kodiak NWR	3-Year Max	0.0002	0.002	0.005

TABLE 9.2.5-13 Cumulative Deposition Results for the LNG Plant and Marine Terminal Plus Offsite Sources				
Class I/II Area	Year	Sulfur Predicted Impact (kg/ha/yr)	Nitrogen Predicted Impact (kg/ha/yr)	Class I Deposition Analysis Thresholds (kg/ha/yr)
Tuxedni NWR	3-Year Max	0.054	0.119	0.125
DNPP	3-Year Max	0.080	0.093	0.125
Kenai Fjords National Park	3-Year Max	0.002	0.014	0.125
Chugach National Forest	3-Year Max	0.030	0.073	0.125
Lake Clark National Park	3-Year Max	0.053	0.122	0.125
Kodiak NWR	3-Year Max	0.027	0.018	0.125

As shown in Table 9.2.5-12, modeled sulfur deposition is slightly above the DAT at Tuxedni NWR and Lake Clark National Park while modeled nitrogen deposition is above the DAT at Tuxedni NWR, the DNPP, and Lake Clark National Park. At the same time Table 9.2.5-13 demonstrates that modeled cumulative deposition rates for sulfur and nitrogen are below the DAT for all Class I and Sensitive Class

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II areas in the far-field analysis. Thus, overall cumulative impacts from the Liquefaction Facility and other emission sources should not be a concern.

9.2.5.1.7 Ozone and Secondary Particulate Matter Assessment

The processes involved in the formation and reduction of ozone and secondary PM_{2.5} were reviewed to provide a qualitative assessment of the level of concern. The intent is to help with the understanding of the formation and loss processes in general, but also in relation to the specific characteristics of the sub-arctic atmosphere. A complete analysis is provided in Appendix D.

A review of available monitoring data near the Project vicinity showed that neither ozone nor PM_{2.5} current concentrations are or have been in exceedance of the NAAQS/AAQS despite continual development in Southcentral Alaska. Furthermore, back trajectory analysis for selected episodes identified from the monitoring data suggests that observed concentrations could be at least in part the result of pollution transported from Anchorage and mid-latitude regions.

Using available tools, a conservative quantification of the potential regional impact of the Liquefaction Facility in both ozone and PM_{2.5} was developed. The information provided in this analysis is very conservative as it relies on photochemical modeling performed for the continental United States, which does not account for the chemical complexities (halogen chemistry), the seasonal pattern (photochemical shutdown in the winter), and the global boundary influences (long-range transport contribution to pollution from Asia and Europe) known to occur in Alaska.

The analysis presented in Appendix D indicates that emissions from the Liquefaction Facility would at most lead to ozone increments of about 3 ppbv. Note that this increase is not additive, otherwise the cumulative effect of existing sources would have already affected the monitoring record. Also, the location of peak impact is likely to be variable in space and time. This maximum increase of 0.003 ppmv (3 ppbv) in a region where ozone design values currently range around 0.045 ppmv would not lead to non-attainment issues in the region.

For PM_{2.5}, the analysis presented in Appendix D indicates that emissions from the Liquefaction Facility would at most lead to nitrate increments of about 1 µg/m³ and sulfate increments of less than 2 µg/m³ for the 24-hour averaging period. These would be the estimated PM_{2.5} impacts that are not expected to occur near the source, but downwind as the result of secondary formation. Just as with ozone, this increase is not additive and the location of peak impact likely to be variable in space and time. This maximum increase of less than 3 µg/m³ in a region where PM_{2.5} concentrations range around 10 µg/m³ would not lead to nonattainment issues in the region. Furthermore, the formation of ammonium sulfate and nitrate would be significantly limited by the availability of ammonia.

The assessment suggests there is little concern about formation of ozone and secondary PM_{2.5} as a result of operation of the Liquefaction Facility.

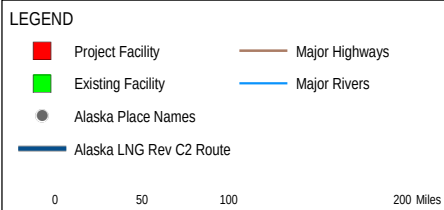
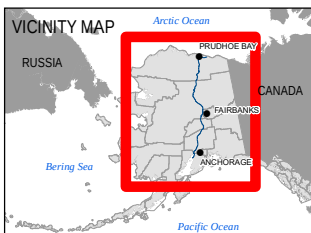
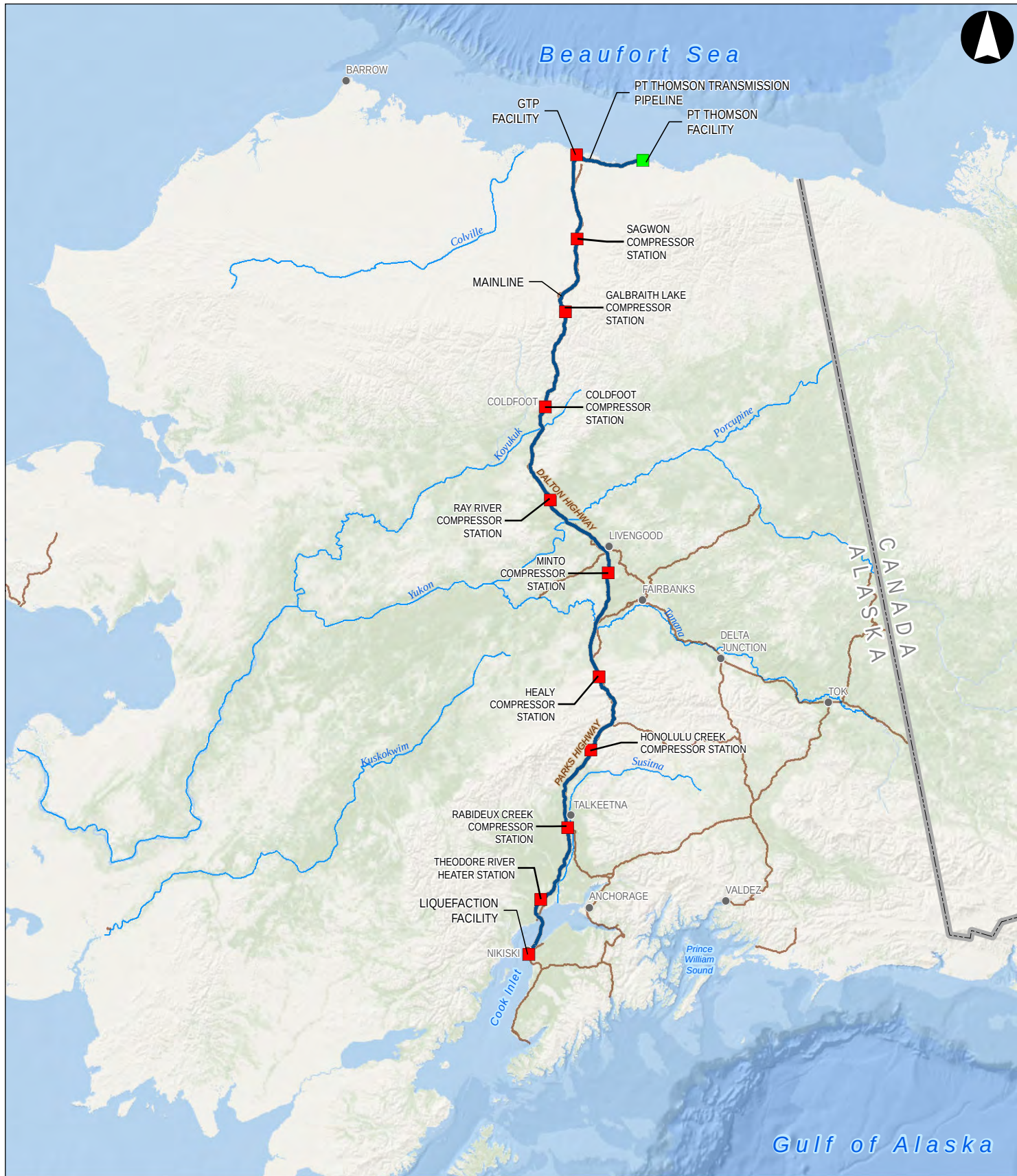
9.2.5.2 Interdependent Project Facilities

9.2.5.2.1 Mainline

The Mainline would be an approximately 806-mile, 42-inch natural gas pipeline transporting 3.3 billion cubic feet per day of treated gas at 2,075 pounds per square inch (psig) maximum allowable operating pressure from the GTP located at Prudhoe Bay to the Liquefaction Facility located near Nikiski, Alaska.

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Once in operation, emission sources from the Mainline would include eight compressor stations, and one standalone heater station. Based on the proposed design, other aboveground pipeline facilities, such as metering stations, would not have permitted emission “point” sources, but would include fugitive emissions. Each compressor and heater stations, is anticipated to trigger the minor air quality control permit requirements under 18 AAC 50.502(c)(1). Compressor and heater station locations are shown in Figure 9.2.5-1.



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**COMPRESSOR AND
HEATER STATION
LOCATIONS**

FIGURE 9.2.5-1

ALASKA LNG

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9.2.5.2.1.1 Compressor and Heater Stations Emissions

The design equipment for each of the compressor stations is shown in Table 9.2.5-14. The Sagwon Compressor Station would operate two turbine-driven compressors, with one available for standby; the other compressor stations have single-unit turbine-driven compressors. All sites would include power generators, auxiliary glycol heaters or indirect fired heaters, and waste incinerators. Operation of these units is described in Appendix E.

TABLE 9.2.5-14 Compressor Station Emission Unit Inventory		
Station	Station Type (Nominal Horsepower [HP])	Major Equipment (Number of Units)
Sagwon	Multi-Unit with Cooling (~68,000 HP)	Turbine-driven Compressors (3) Power Generators (4) Auxiliary Utility Glycol Heaters (2) Waste Incinerator (1)
Galbraith Lake, Coldfoot, Ray River, Minto, Healy	Single-Unit with Cooling (~42,000 HP)	Turbine-driven Compressor (1) Power Generators (3) Auxiliary Utility Glycol Heaters (2) Waste Incinerator (1)
Honolulu Creek, Rabideux Creek	Single-Unit without Cooling (~33,000 HP)	Turbine-driven Compressor (1) Power Generators (3) Auxiliary Utility Glycol Heaters (2) Waste Incinerator (1)
Theodore River	Heater Station	Power Generators (3) Indirect Fired Gas Heaters (9) Waste Incinerator (1)

Total estimated annual emissions of criteria air pollutants from each type of compressor stations is shown in Table 9.2.5-15 with further details included Appendix F of Appendix E. Based on these data, each of the compressor and heater stations would require an air quality construction permit from ADEC prior to construction.

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TABLE 9.2.5-15 Total Annual Emissions from Compressor and Heater Station Operations (tons/year)				
Pollutant	Multiple Turbine Compressor Station with Cooling (Sagwon)	Single Turbine Compressor Station with Cooling (Galbraith Lake, Coldfoot, Ray River, Minto, Healy)	Single Turbine Compressor Station without Cooling (Honolulu Creek), Rabideux Creek	Heater Station (Theodore River)
NO _x	185	161	131.2	49
CO	248	244	200	103
VOCs	34	21	13.9	16.2
PM/PM ₁₀ /PM _{2.5} ^a	29	13.1	10.6	8.7
SO ₂	4.8	4.3	3.5	2.6
Maximum HAP	7.9	6.3	5.0	2.1
Total HAPs	10.7	8.3	6.6	4.2
GHGs ^b	233,784	206,382	166,013	125,201
^a Potential PM ₁₀ and PM _{2.5} emissions are conservatively assumed to equal potential PM emissions. ^b Annual emissions of GHGs are given in metric tons (tonnes) of CO ₂ e per year.				

Fugitive emissions of organic compounds, including some HAPs, would be emitted from piping components and connectors throughout the compressor station. The total estimated fugitive emissions of GHGs, VOCs, and HAPs from normal operation of each compressor station are included in Table 9.2.5-15, along with the emission rate for the highest (maximum) emitted HAP, which is essential in determining the requirements for emissions of HAPs. Fugitive emissions for each of the compressor stations were calculated based on preliminary component counts and the EPA emission factors found in Table 2-4 of the EPA Protocol for Equipment Leak Emissions (EPA-453/R-95-017, November 1995) and subsequent procedures.

9.2.5.2.1.2 Compressor and Heater Station Ambient Air Quality Impact Analysis

To assess air quality impacts, dispersion modeling was conducted using the AERMOD and the AERMAP, AERSURFACE, AERMET, and BPIP pre-processors, in accordance with EPA's Guideline on Air Quality Models (40 C.F.R. 51 Appendix W) and ADEC's Modeling Review Procedures Manual (ADEC, 2016b).

Due to the sparse nature of meteorological stations through the rugged terrain of Alaska, virtual onsite meteorological tower data were produced for each of the compressor and heater stations (with the exception of Galbraith Lake) using prognostic meteorological data. Two different prognostic datasets have been developed to cover the state—the Weather Research and Forecasting Model, or WRF, data and the Fifth Generation Penn State/NCAR Mesoscale Model, or MM5, data. The WRF dataset is for three years (2007–2009) and covers the North Slope down to the south side of the Brooks Range, while the MM5 dataset is for the three years (2002–2004) and covers Southcentral Alaska into the Interior. WRF

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data was used to model the Sagwon, Coldfoot, Ray River, and Minto compressor stations; MM5 data was used to model the Healy, Honolulu Creek, and Rabideux Creek compressor stations plus the Theodore River heater station. For the Galbraith Lake compressor station, meteorological data for April 2002 through March 2003 collected nearby at Alyeska Pipeline Pump Station 4 (PS 4) was used for modeling. For further details on meteorological data used to model Mainline facilities, see Appendix E, Section 5.2.

Each compressor and heater station was modeled using the most recent site layout, local terrain features, and a receptor grid established at the facility fence line and beyond. As discussed in Section 9.2.2.1, ambient air quality data are sparse along much of the pipeline corridor. Available datasets were carefully reviewed, and background concentrations for each compressor station location were identified from the nearest available, representative monitoring site. Details of the modeling effort, including the background concentration locations, are included in Appendix E.

The proposed compressor and heater stations are generally located in remote areas away from other stationary sources. This analysis does not include modeled pollutant impacts from any offsite sources with the exception of the Galbraith Lake. The Galbraith Lake compressor station would be located approximately 1.5 kilometers southeast PS 4. Due to its proximity to the proposed Galbraith Lake compressor station, emissions from PS 4 were included in the modeling analyses for Galbraith Lake. PS 4 emission rates and source parameters used in the modeling are provided in Appendix E.

A formal modeling protocol would be submitted to ADEC for concurrence, then an ambient air quality impact analysis would be completed as part of the air permit application for the compressor and heater stations. In advance of the formal protocol, a “modeling approach” was circulated to EPA, FLMs, ADEC, and FERC. Subsequent dialogue and correspondence with these agencies has helped to guide the modeling impact analysis for this Resource Report.

A nested receptor grid was used to capture impacts. Receptor spacing of 25 meters was established along the ambient air boundary out to 100 meters, extending through additional grids of 100, 250, and 500 meters out to 10 kilometers from each facility. Predicted maximum air quality impacts for criteria air pollutants, including modeled results plus representative background concentrations, are summarized in Table 9.2.5-16. Supporting documentation is provided in Appendix E.

TABLE 9.2.5-16 Air Quality Impact Analysis for Compressor Stations – Normal Operations (µg/m ³)								
Station	NO ₂		PM _{2.5} ^a		SO ₂		CO	
	Max. 1-hr	Annual	Max. 24-hr	Annual	Max 1-hr ^b	Annual	Max 1-hr	Max 8-hr
Sagwon	133	7.9	19.5	3.2	19.4	1.0	944	754
Galbraith Lake	152	10.7	15.7	4.2	35.3	2.6	1,117	710
Coldfoot	117	9.2	22.7	5.3	21.0	3.6	984	857
Ray River	142	11.2	25.6	4.5	19.6	2.2	950	735
Minto	134	10.3	21.2	5.1	18.8	3.6	934	762
Healy	105	14.8	19.2	3.8	29.2	1.8	8,587	5,336
Honolulu Creek	104	19.6	19.0	4.3	19.8	2.4	8,343	5,302

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TABLE 9.2.5-16 Air Quality Impact Analysis for Compressor Stations – Normal Operations (µg/m ³)								
Station	NO ₂		PM _{2.5} ^a		SO ₂		CO	
	Max. 1-hr	Annual	Max. 24-hr	Annual	Max 1-hr ^b	Annual	Max 1-hr	Max 8-hr
Rabideux Creek	87	5.9	13.6	2.7	17.2	1.5	8,276	5,246
Theodore River	130	13.2	26.7	4.1	16.0	1.3	8,323	5,339
NAAQS/AAQS	188	100	35	12	196	80	40,000	10,000
^a PM ₁₀ concentration is conservatively assumed to equal PM _{2.5} . Only PM _{2.5} is shown here because it is most stringent. ^b Maximum 3-hour and 24-hour SO ₂ concentrations are assumed to equal one-hour SO ₂ concentration. Only 1-hour SO ₂ is shown here since it is most stringent.								

All results, modeled following the above-described conservative screening procedures, demonstrate compliance with the National and Alaska AAQS.

9.2.5.2.1.3 Compressor and Heater Station AQRV Analysis

The 806-mile long Mainline traverses a long corridor across Alaska near many Class I and Sensitive Class II areas. See Figure 9.2.2-7.

As a preliminary step in evaluating AQRVs at Class I and Sensitive Class II areas, the FLAG (2010) guidance for screening areas more than 50 kilometers from a compressor or heater station based on the Q/D method was applied. Using this method, all areas over 50 kilometers from any of the compressor or heater stations are below the FLAG de minimis for evaluation and no further analysis is warranted. See details in Appendix E, Section 3.2.4. That is, the impacts are so small that compressor and heater stations do not require any far-field (50 kilometers or further) analysis.

AQRVs at all Class I and Sensitive Class II areas within 50 kilometers of a compressor or heater station were evaluated following the FLAG near-field analysis methods. These areas are identified in Table 9.2.5-17. See, also, Appendix E, Figures 2 and 3.

TABLE 9.2.5-17 Class I and Sensitive Class II Areas Included in the AQRV Analysis for Compressor and Heater Stations		
Compressor/Heater Station	Class I Areas (approx. distance from Compressor Station)	Sensitive Class II Areas Warranting AQRV Evaluation (approx. distance from Compressor Station)
Sagwon	None	Arctic NWR (30 km)
Galbraith Lake	None	Arctic NWR (3.3 km) Gates of the Arctic National Park and Preserve (11 km)
Coldfoot	None	Gates of the Arctic National Park and Preserve (8.8 km) Yukon Flats NWR (44 km)
Ray River	None	Yukon Flats NWR (17 km) Kanuti NWR (36 km)

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TABLE 9.2.5-17 Class I and Sensitive Class II Areas Included in the AQRV Analysis for Compressor and Heater Stations		
Compressor/Heater Station	Class I Areas (approx. distance from Compressor Station)	Sensitive Class II Areas Warranting AQRV Evaluation (approx. distance from Compressor Station)
Minto	None	None
Healy	DNPP (4.7 km)	None
Honolulu Creek	DNPP (14 km)	None
Rabideux Creek	None	None
Theodore River	None	Kenai NWR (46 km)

Complete details of the visibility and deposition AQRV analyses at these areas are provided in Appendix E.

The model used for all visibility analysis was VISCREEN using the Level 1 or 2 assessment methodology as appropriate. VISCREEN requires emission rates of NO_x and primary particulate, which were based on the compressor station and heater station emissions in Sections 9.2.5.3.1.1. For Level 2 assessments, meteorological conditions were based on the same WRF or MM5 prognostic datasets as described in Section 9.2.5.3.1.2. Background visual range was based on FLAG (2010) for the DNPP for the Healy and Honolulu compressor stations, and for Tuxedni NWR for the Theodore River Heater Station. Background visual range for all other compressor stations was assumed to be 258 kilometers, the default in the ADEC (2016b) modeling guidance. The conservative VISCREEN default parameters were assumed for other model inputs. See Appendix E for more details. Results are provided in Table 9.2.5-18.

TABLE 9.2.5-18							
VISCREEN Results for Compressor and Heater Station Impacts at Class I and Sensitive Class II Areas							
Source	Observer	Background	VISCREEN Mode	Contrast (Cp)		Perceptibility (ΔE)	
				Criteria	Modeled	Criteria	Modeled
Forward Scatter, Sky Background							
Healy	Inside Denali	SKY	Level 2	2.00	1.36	0.05	0.01
	Outside Denali	SKY	Level 2	2.00	3.19	0.05	-0.03
Honolulu Creek	Inside Denali	SKY	Level 2	2.00	0.30	0.05	0.00
	Outside Denali	SKY	Level 2	2.00	2.05	0.05	0.01
Sagwon	Arctic NWR	SKY	Level 2	2.00	1.46	0.05	0.02
Galbraith Lake	Arctic NWR	SKY	Level 2	2.00	1.83	0.05	0.01
	Gates of the Arctic National Park and Preserve	SKY	Level 2	2.00	0.83	0.05	0.01
Coldfoot	Gates of the Arctic National Park and Preserve	SKY	Level 2	2.00	0.87	0.05	0.01

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TABLE 9.2.5-18							
VISCREEN Results for Compressor and Heater Station Impacts at Class I and Sensitive Class II Areas							
Source	Observer	Background	VISCREEN Mode	Contrast (Cp)		Perceptibility (ΔE)	
				Criteria	Modeled	Criteria	Modeled
	Yukon Flats	SKY	Level 1	2.00	1.87	0.05	0.01
Ray River	Kanuti	SKY	Level 1	2.00	1.87	0.05	0.01
	Yukon Flats	SKY	Level 2	2.00	0.17	0.05	0.00
Theodore River	Kenai NWR	SKY	Level 1	2.00	0.63	0.05	0.01
Backward Scatter, Sky Background							
Healy	Inside Denali	SKY	Level 2	2.00	0.92	0.05	-0.01
	Outside Denali	SKY	Level 2	2.00	1.86	0.05	-0.03
Honolulu Creek	Inside Denali	SKY	Level 2	2.00	0.23	0.05	-0.00
	Outside Denali	SKY	Level 2	2.00	1.31	0.05	-0.02
Sagwon	Arctic NWR	SKY	Level 2	2.00	0.76	0.05	-0.01
Galbraith Lake	Arctic NWR	SKY	Level 2	2.00	1.21	0.05	-0.02
Galbraith Lake	Gates of the Arctic National Park and Preserve	SKY	Level 2	2.00	0.61	0.05	-0.01
Coldfoot	Gates of the Arctic National Park and Preserve	SKY	Level 2	2.00	0.63	0.05	-0.01
	Yukon Flats	SKY	Level 1	2.00	1.27	0.05	-0.02
Ray River	Kanuti	SKY	Level 1	2.00	1.26	0.05	-0.02
	Yukon Flats	SKY	Level 2	2.00	0.11	0.05	-0.00
Theodore River	Kenai NWR	SKY	Level 1	2.00	0.33	0.05	-0.01
Forward Scatter, Terrain Background							
Healy	Inside Denali	TERRAIN	Level 2	2.00	1.91	0.05	0.02
	Outside Denali	TERRAIN	Level 2	2.00	4.94	0.05	0.05
Honolulu Creek	Inside Denali	TERRAIN	Level 2	2.00	0.50	0.05	0.00
	Outside Denali	TERRAIN	Level 2	2.00	2.80	0.05	0.03
Sagwon	Arctic NWR	TERRAIN	Level 2	2.00	1.66	0.05	0.01
Galbraith Lake	Arctic NWR	TERRAIN	Level 2	2.00	2.56	0.05	0.03
Galbraith Lake	Gates of the Arctic National Park and Preserve	TERRAIN	Level 2	2.00	1.29	0.05	0.01
Coldfoot	Gates of the Arctic National Park and Preserve	TERRAIN	Level 2	2.00	1.31	0.05	0.01

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TABLE 9.2.5-18							
VISCREEN Results for Compressor and Heater Station Impacts at Class I and Sensitive Class II Areas							
Source	Observer	Background	VISCREEN Mode	Contrast (Cp)		Perceptibility (ΔE)	
				Criteria	Modeled	Criteria	Modeled
	Yukon Flats	TERRAIN	Level 1	2.00	0.19	0.05	0.00
Ray River	Kanuti	TERRAIN	Level 1	2.00	1.05	0.05	0.01
	Yukon Flats	TERRAIN	Level 2	2.00	0.29	0.05	0.00
Theodore River	Kenai NWR	TERRAIN	Level 1	2.00	0.23	0.05	0.00
Backward Scatter, Terrain Background							
Healy	Inside Denali	TERRAIN	Level 2	2.00	0.65	0.05	0.01
	Outside Denali	TERRAIN	Level 2	2.00	1.52	0.05	0.01
Honolulu Creek	Inside Denali	TERRAIN	Level 2	2.00	0.11	0.05	0.00
	Outside Denali	TERRAIN	Level 2	2.00	1.06	0.05	0.01
Sagwon	Arctic NWR	TERRAIN	Level 2	2.00	0.12	0.05	0.00
Galbraith Lake	Arctic NWR	TERRAIN	Level 2	2.00	0.90	0.05	0.01
	Gates of the Arctic National Park and Preserve	TERRAIN	Level 2	2.00	0.34	0.05	0.00
Coldfoot	Gates of the Arctic National Park and Preserve	TERRAIN	Level 2	2.00	0.38	0.05	0.00
	Yukon Flats	TERRAIN	Level 1	2.00	0.02	0.05	0.00
Ray River	Kanuti	TERRAIN	Level 1	2.00	0.13	0.05	0.00
	Yukon Flats	TERRAIN	Level 2	2.00	0.05	0.05	0.00
Theodore River	Kenai NWR	TERRAIN	Level 1	2.00	0.06	0.05	0.00

As shown in Table 9.2.5-18, results for almost all of the combinations of compressor and heater stations and Class I and Sensitive Class II areas are below the screening thresholds below which no concern exists. For three scenarios, the Healy and Honolulu Creek compressor stations outside the DNPP and the Galbraith Lake Compressor Station at Gates of the Arctic National Park, results are above the screening criteria.

Deposition modeling at the compressor and heater stations used the AERMOD model, Level 1 screening procedures in FLAG (2010), and the Federal Land Managers' Draft Interagency Guidance for Near Field Deposition Modeling (USDOI 2014). See Appendix E for further details. Extensive receptor grids were developed radially from each compressor/heater station out 50 kilometers in all directions to capture screening level impacts at each Class I and Sensitive Class II area. See Attachment D to Appendix E.

The results are provided in Table 9.2.5-19 and can be compared to the Class I screening deposition analysis thresholds (DATs) of 0.005 kg/ha/yr. As shown in Table 9.2.5-19, screening analyses are not

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able to demonstrate that nitrogen deposition would be below the DAT at any of the Class I and Sensitive Class II areas within 50 kilometers of a compressor or heater station. Sulfur deposition screening results are above the DAT at the Arctic NWR (ANWR) for the Galbraith Lake Compressor Station, but below the DAT for all other scenarios.

TABLE 9.2.5-19 Deposition Results for Compressor and Heater Station Impacts at Class I and Sensitive Class II Areas			
Station	Class I/II Area (within 50 km)	Species	Maximum Modeled Deposition (kg/ha/yr)
Sagwon Compressor Station	Arctic National Wildlife Refuge (ANWR)	Nitrogen	0.062
		Sulfur	<0.005
Galbraith Lakes Compressor Station	ANWR	Nitrogen	1.937
		Sulfur	0.030
	Gates of the Arctic National Park and Preserve	Nitrogen	0.147
		Sulfur	<0.005
Coldfoot Compressor Station	Gates of the Arctic National Park and Preserve	Nitrogen	0.395
		Sulfur	<0.005
	Yukon Flats NWR	Nitrogen	0.011
		Sulfur	<0.005
Ray River Compressor Station	Kanuti NWR	Nitrogen	0.102
		Sulfur	<0.005
	Yukon Flats NWR	Nitrogen	0.115
		Sulfur	<0.005
Healy Compressor Station	DNPP	Nitrogen	0.273
		Sulfur	<0.005
Honolulu Creek Compressor Station	DNPP	Nitrogen	0.084
		Sulfur	<0.005
Theodore River Compressor Station	Kenai NWR	Nitrogen	0.030
		Sulfur	<0.005

9.2.5.2.1.4 Other Aboveground Pipeline Facilities

There are no proposed combustion sources emission units at other aboveground facilities along the Mainline.

Fugitive emissions of organic compounds, including the GHGs methane and CO₂, would be emitted from piping components and connectors along the pipelines (Mainline, PTTL, and PBTTL). The Interstate Natural Gas Association of America has created guidance for calculating CH₄ and CO₂ leak emissions from a natural gas pipeline. The methodology uses the length of the aboveground pipeline, based on the assumption of cathodic protection, and the number of meter stations to determine an estimate of the annual fugitive emissions. There are four metering stations planned—three in the vicinity of the GTP and one at the inlet to the Liquefaction Facility. There are 30 mainline block valves (MLBVs) in the proposed design.

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Table 9.2.5-20 provides the estimated annual fugitive GHG emissions for these pipeline operations (excluding the GTP and compressor station fugitives, which are included in those facilities).

TABLE 9.2.5-20 Estimated Pipeline Fugitive Greenhouse (GHG) Gas Emissions				
Pollutant	Segment	No. of stations or miles	Emission Factor ^{a,b}	Emissions (tonnes per year)
MAINLINE				
Methane (CH ₄)	Meter/Regulator	2	2,533 lb CH ₄ /station-yr	2.30
	Pipeline Length	806	23.08 lb CH ₄ /mile-yr	8.44
Carbon Dioxide (CO ₂)	Meter/Regulator	2	146.34 lb CO ₂ /station-yr	0.13
	Pipeline Length	806	1.52 lb CO ₂ /mile-yr	0.56
CO ₂ from CH ₄ Oxidation	Pipeline Length	806	7.59 lb CO ₂ /mile-yr	2.77
Mainline Total GHG Emissions (CO ₂ e) ^c				271.86
PTTL				
Methane (CH ₄)	Meter/Regulator	1	2,533 lb CH ₄ /station-yr	1.15
	Pipeline Length	63	23.08 lb CH ₄ /mile-yr	0.66
Carbon Dioxide (CO ₂)	Meter/Regulator	1	146.34 lb CO ₂ /station-yr	0.07
	Pipeline Length	63	1.52 lb CO ₂ /mile-yr	0.04
CO ₂ from CH ₄ Oxidation	Pipeline Length	63	7.59 lb CO ₂ /mile-yr	0.22
PTTL Total GHG Emissions (CO ₂ e) ^c				45.54
PBTL				
Methane (CH ₄)	Meter/Regulator	1	2,533 lb CH ₄ /station-yr	1.15
	Pipeline Length	1	23.08 lb CH ₄ /mile-yr	0.01
Carbon Dioxide (CO ₂)	Meter/Regulator	1	146.34 lb CO ₂ /station-yr	0.07
	Pipeline Length	1	1.52 lb CO ₂ /mile-yr	0.001
CO ₂ from CH ₄ Oxidation	Pipeline Length	1	7.59 lb CO ₂ /mile-yr	0.003
PBTL Total GHG Emissions (CO ₂ e) ^c				29.06
Total Pipeline Fugitive GHG Emissions (CO ₂ e) ^c				346.46
^a The meter/regulator emission factor is in units of pounds per station per year. ^b The pipeline length emission factor is in units of pounds per mile per year. ^c The total GHG emissions are calculated as CO ₂ e emissions, i.e., the sum of individual GHGs with the annual tons of each gas multiplied by its GWP relative to CO ₂ . Source: Interstate Natural Gas Association of America 2005, Table 4-3.				

9.2.5.2.2 Point Thomson and Prudhoe Bay Gas Transmission Lines

There are no combustion emission sources required for operation of either the PTTL or PBTL. Estimates of fugitive GHG emissions from operation of these pipelines are provided in Table 9.2.5-20.

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9.2.5.2.3 Gas Treatment Plant Emissions

The design of the GTP consists of three identical gas processing trains that receive gas from the PTU and PBU, clean the gas by removing CO₂ and H₂S and send this Byproduct stream back to Prudhoe Bay, remove any water and inject it down a Class I well, then ship the remaining natural gas down the Mainline to the LNG Plant in Nikiski. See Resource Report No. 1 for a complete description of the GTP.

A number of air emission units are required to operate the GTP:

- Approximately 298,000 International Organization for Standardization (ISO) horsepower of mechanical drive natural gas turbine capacity to support treated gas compression;
- Approximately 205,000 ISO horsepower of mechanical drive natural gas turbine capacity to support Byproduct gas (CO₂) compression;
- Approximately 230 ISO MW of natural gas turbine capacity to support power generation;
- Supplemental firing of waste heat recovery units associated with mechanical drive;
- Natural gas-fired common utility heaters (two primary, one reserve);
- Diesel-fired essential generator;
- Diesel-fired firewater pumps;
- A dormitory emergency diesel generator;
- A communications tower diesel generator;
- Buyback gas bath heaters;
- Camp heaters;
- Low pressure CO₂ flares;
- High pressure CO₂ flares;
- Low pressure hydrocarbon flares; and
- High pressure hydrocarbon flares.

Emissions estimates are based on preliminary Project design data for equipment and operations. Key input data are the total firing rate for turbines and heaters, hours of operation, projected load, the projected gas heat content, and projected use of diesel fired engines. Emission factors are derived from standard databases or vendor data from typical sources such as turbines, heaters, and engines. Vendor data that are used are considered representative of emissions, but are not implied as the data for the final design

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equipment. Details of the equipment design, fuel use, hours of operation, emission factors, projected load factors, and other operational considerations are provided in Appendix F.

Fugitive emissions of organic compounds would be emitted from piping components and connectors throughout the GTP. Emissions are estimated from component counts (valves, flanges, pumps, compressors, etc.) and EPA and industry emission factors.

Based on the proposed design, short-term and annual emissions from operation of this equipment, including fugitive emissions and potential HAPs, are provided in Table 9.2.5-21. Emission calculations are included in Appendix F. Hourly and short-term emissions are based on worst-case assumptions regarding performance and maximum facility design capabilities, using vendor-supplied emission data, where available, or standard emission factors that are cited in the Appendix. Emissions are for normal operation of the GTP. Sulfur dioxide emissions reflect the use of “raw” fuel gas, which is expected to be used on initial facility commissioning. Use of “treated” fuel gas after commissioning is expected to reduce sulfur dioxide emissions by approximately 80 percent.

TABLE 9.2.5-21 Total Emissions from GTP Operations		
Pollutant	GTP Potential to Emit (pounds per hour)	GTP Potential to Emit (tons per year)
Nitrogen Oxides (NO _x)	682	2,242
Carbon Monoxide (CO)	767	2,080
Volatile Organic Compounds (VOCs)	97	354
Particulate Matter (PM ₁₀)	69	264
Particulate Matter (PM _{2.5})	69	264
Sulfur Dioxide (SO ₂) ^c	157	593
Largest Individual Hazardous Air Pollutant (Formaldehyde)	5.9	25.8
Total Hazardous Air Pollutants (HAPs)	9.8	42
Total GHG Emissions (CO ₂ e) ^{a,b}	Not Applicable	4,201,860
^a Annual emissions of GHGs are given in metric tons (tonnes) per year. ^b The total GHG emissions are calculated as CO ₂ equivalent (CO ₂ e) emissions. ^c SO ₂ emissions based on commissioning when part of the facility will combust raw gas with 90 ppmv H ₂ S. This severely overstates PTE for normal GTP operations which will likely be based on 16 ppmv H ₂ S. Normal operations PTE can be estimated by multiplying listed values by 16/90		

GTP Near-Field Analyses – Ambient Air Quality Impacts

Air quality impacts from GTP operations would result from the emissions units identified above—primarily natural gas-fired compression turbines, power generation turbines, and utility heaters. Additionally, the GTP would include auxiliary and emergency RICEs, auxiliary and camp heaters, and

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emergency CO₂ and hydrocarbon flares, which may also have small emission rates from pilot and purge gas.

To assess air quality impacts, dispersion modeling was conducted using the AERMOD model Version 15181, with AERMET and BPIP pre-processors, in accordance with EPA's Guideline on Air Quality Models (40 C.F.R. 51 Appendix W) and ADEC's Modeling Review Procedures Manual (ADEC, 2016b). The proposed GTP site is located approximately 6 miles northeast of the A Pad meteorological and air quality monitoring station. A Pad meteorological data are considered representative of dispersion conditions in the near-field of the GTP due to its close proximity and lack of significant terrain features between the two. Thus, five years of recent (2010–2014) PSD-quality A Pad data were used in this modeling in accordance with EPA and ADEC modeling guidance. Concurrent upper air data from Barrow, Alaska, located approximately 325 kilometers northwest of the GTP, were used in this modeling effort.

A nested receptor grid was used to predict impacts. Receptor spacing of 82 feet (25 meters) was established along the pad edge out to 328 feet (100 meters), extending through additional grids of 164 feet (50 meters), 328 feet (100 meters), 820 feet (250 meters), and 1,640 feet (500 meters) out to 6.2 miles (10 kilometers) from the GTP. Background air quality data in the vicinity of GTP were calculated from the A Pad and Prudhoe Bay Central Compression Plant PSD-quality monitoring sites for calendar years 2009–2013. Data collected at these ambient air stations are considered conservatively representative of the GTP site and non-modeled sources since the monitoring stations are located downwind of existing large stationary sources, well site activities, and mobile sources typical of the Prudhoe Bay oilfield development. Details of this modeling effort are included in Appendix F.

A formal modeling protocol would be submitted to ADEC for concurrence, then an ambient air quality impact analysis would be completed as part of the air permit application for the GTP. In advance of the protocol, a “modeling approach” and draft modeling protocol were circulated to the EPA, FLMs, ADEC, and FERC. Subsequent dialogue and correspondence with these agencies has helped to guide the modeling impact analysis, including AQRV analysis, for this Resource Report.

The analysis herein is focused on characterizing GTP standalone and cumulative impacts utilizing the modeling approach outlined above and in Appendix F. Predicted impacts are summarized in Table 9.2.5-22, along with the NAAQS and Alaska AAQS, and in Table 9.2.5-23 for the PSD Increments. The modeling results, when added to representative background air quality concentrations, demonstrate compliance with the NAAQS and Alaska AAQS, as well as the PSD Increments.

TABLE 9.2.5-22						
Air Quality Impact NAAQS/AAQS Analysis at the Gas Treatment Plant – Normal Operations						
Air Pollutant	Averaging Period	Model-Predicted (Project-only) Concentration (µg/m ³)	Ambient Background Concentration (µg/m ³)	Total Concentration (µg/m ³)	NAAQS (µg/m ³)	AAQS (µg/m ³)
Sulfur Dioxide	1-Hour ^a	11.2	9.39	20.6	196	196
	3-Hour ^b	37.7	21.0	58.7	1,300	1,300
	24-Hour ^b	11.2	8.12	19.3	---	365
	Annual ^d	0.54	1.80	2.34	---	80

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TABLE 9.2.5-22						
Air Quality Impact NAAQS/AAQS Analysis at the Gas Treatment Plant – Normal Operations						
Air Pollutant	Averaging Period	Model-Predicted (Project-only) Concentration (µg/m³)	Ambient Background Concentration (µg/m³)	Total Concentration (µg/m³)	NAAQS (µg/m³)	AAQS (µg/m³)
Carbon Monoxide	1-Hour ^b	366	1,150	1,516	40,000	40,000
	8-Hour ^b	139	1,150	1,289	10,000	10,000
Nitrogen Dioxide	1-Hour ^c	65.0	NA ^g	65.0	188	188
	Annual ^d	2.62	6.00	8.62	100	100
Particulate Matter less than 10 Microns	24-Hour ^f	3.77	50.0	53.8	150	150
Particulate Matter less than 2.5 Microns	24-Hour ^e	3.29	15.0	18.3	35	35
	Annual ^h	0.22	3.70	3.92	12	12
<u>Notes:</u> µg/m³ = micrograms per cubic meter ^a Value is the 99th percentile of the distribution of daily maximum values. ^b Value is the highest, second highest concentration of the values determined for each of the five modeled years. ^c Value is the 98th percentile of the distribution of daily maximum values. ^d Value is the maximum annual average concentration for the five -year period. ^e Value is the 98th percentile averaged over the five -year period. ^f Value is the highest, 5th highest concentration over the five -year period. ^g The 1-hour NO₂ modeling was conducted with wind speed-varying background values applied by hour in AERMOD. Therefore, the AERMOD-predicted 1-hour NO₂ concentration includes the background. ^h Value is the annual mean concentration averaged over the five -year period.						

TABLE 9.2.5-23			
Increment Analysis for the Gas Treatment Plant – Normal Operations			
Air Pollutant	Averaging Period	Model-Predicted Concentration (µg/m³)	Class II Increments (µg/m³)
Sulfur Dioxide	1-Hour ^a	NA	NA
	3-Hour ^b	37.7	512
	24-Hour ^b	11.2	91
	Annual ^c	0.5	20
Nitrogen Dioxide	Annual ^c	2.6	25
Particulate Matter less than 10 Microns	24-Hour ^b	4.8	30
	Annual ^c	0.3	17
Particulate Matter less than 2.5 Microns	24-Hour ^b	4.8	9
	Annual ^c	0.3	4

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TABLE 9.2.5-23 Increment Analysis for the Gas Treatment Plant – Normal Operations			
Air Pollutant	Averaging Period	Model-Predicted Concentration (µg/m ³)	Class II Increments (µg/m ³)
Abbreviations: NA = not applicable µg/m ³ = micrograms per cubic meter Notes: ^a Neither USEPA nor ADEC have established increment thresholds for 1-hr NO ₂ , 1-hr SO ₂ , 1-hr CO, or 8-hr CO. ^b Value reported is the maximum of the highest-second-high values from each of the five modeled years. ^c Value reported is the maximum annual average concentration for the five-year period.			

In addition to modeling Project emission sources, the Appendix F dispersion analysis also addressed cumulative ambient air quality impacts from the proposed Project and nearby offsite sources. For the GTP cumulative air quality impact analysis, the following offsite sources were considered:

- PBU Central Compression Plant (CCP), and
- PBU Central Gas Facility (CGF).

No other sources were explicitly modeled because they were either not expected to produce a significant concentration gradient in the vicinity of the GTP or were included as part of the background concentration.

Modeled emissions and stack parameters for the CCP and CGF facilities were developed from the respective facility's most recent Title V operating permits and a review of historical dispersion modeling information submitted to ADEC supporting these permit applications. See Appendix F for further details.

Cumulative model-predicted concentrations from the GTP and offsite sources are compared to the NAAQS and AAAQS in Table 9.2.5-24 and to the PSD Increments in Table 9.2.5-25. All model-predicted impacts are below the applicable standards.

TABLE 9.2.5-24 Cumulative NAAQS/AAAQS Analysis for the Gas Treatment Plant – Normal Operations						
Air Pollutant	Averaging Period	AERMOD-Predicted Concentration (µg/m ³)	Ambient Background Concentration (µg/m ³)	Total Concentration (µg/m ³)	NAAQS (µg/m ³)	AAAQS (µg/m ³)
Sulfur Dioxide	1-Hour ^a	39.2	9.39	48.6	196	196
	3-Hour ^b	57	21.0	78	1,300	1,300
	24-Hour ^b	30.1	8.12	38.3	NA	365
	Annual ^d	2.84	1.80	4.64	NA	80
Carbon Monoxide	1-Hour ^b	423	1,150	1,573	40,000	40,000
	8-Hour ^b	302	1,150	1,452	10,000	10,000
Nitrogen Dioxide	1-Hour ^c	158	NA ^g	158	188	188

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TABLE 9.2.5-24 Cumulative NAAQS/AAQs Analysis for the Gas Treatment Plant – Normal Operations						
Air Pollutant	Averaging Period	AERMOD-Predicted Concentration (µg/m³)	Ambient Background Concentration (µg/m³)	Total Concentration (µg/m³)	NAAQS (µg/m³)	AAQs (µg/m³)
	Annual ^d	13.97	6.00	20.0	100	100
Particulate Matter less than 10 Microns	24-Hour ^f	18.4	50.0	68.4	150	150
Particulate Matter less than 2.5 Microns	24-Hour ^e	14.5	15.0	29.5	35	35
	Annual ^h	3.30	3.70	7.00	12	12
Abbreviations: NA = not applicable µg/m³ = micrograms per cubic meter Notes: ^a Value reported is the 99 th percentile of the annual distribution of daily maximum values averaged over the modeled period. ^b Value reported is the highest, second highest concentration of the values determined for each of the modeled years. ^c Value reported is the 98 th percentile of the annual distribution of daily maximum values averaged over the modeled period. ^d Value reported is the maximum annual average concentration for the modeled period. ^e Value reported is the 98 th percentile averaged over the modeled period. ^f Value reported is the highest, 6 th highest concentration over the modeled period. ^g The 1-hour NO ₂ modeling was conducted with wind speed-varying background values applied by hour in AERMOD. Therefore, the AERMOD-predicted 1-hour NO ₂ concentration includes the background. ^h Value reported is the annual mean concentration, averaged over the 5-year period.						

TABLE 9.2.5-25 Cumulative Increment Analysis for the Gas Treatment Plant – Normal Operations			
Air Pollutant	Averaging Period	Model-Predicted Concentration (µg/m³)	Class II Increments (µg/m³)
Sulfur Dioxide	1-Hour ^a	NA	NA
	3-Hour ^b	53	512
	24-Hour ^b	27	91
	Annual ^c	2.0	20
Nitrogen Dioxide	Annual ^c	6.6	25
Particulate Matter less than 10 Microns	24-Hour ^b	12.8	30
	Annual ^c	1.2	17
Particulate Matter less than 2.5 Microns	24-Hour ^b	4.79	9
	Annual ^c	0.3	4

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TABLE 9.2.5-25 Cumulative Increment Analysis for the Gas Treatment Plant – Normal Operations			
Air Pollutant	Averaging Period	Model-Predicted Concentration (µg/m ³)	Class II Increments (µg/m ³)
Abbreviations: NA = not applicable µg/m ³ = micrograms per cubic meter Notes: ^a Neither USEPA nor ADEC have established increment thresholds for 1-hr NO ₂ , 1-hr SO ₂ , 1-hr CO, or 8-hr CO. ^b Value reported is the maximum of the highest-second-high values from each of the five modeled years. ^c Value reported is the maximum annual average concentration for the 5-year period.			

GTP Near-Field Analyses – AQRVs

There are no Class I or Sensitive Class II areas within 50 kilometers of the GTP. See Appendix F, Figure 2-1.

GTP Far-Field Analyses – Ambient Air Quality and AQRVs

Generally ambient air quality impacts decrease with distance from an emission source due to mixing and dilution in the atmosphere. The results for ambient air quality in Section 9.2.5.3.3 demonstrate that there are no issues for the GTP complying with NAAQS, AAAQS, or increments in the near field, and therefore by extension there are no issues in the far field. Thus, the far-field analyses focuses on impacts at Class I and Sensitive Class II areas.

There are no Class I areas within 300 kilometers of the GTP. Sensitive Class II areas in the range of 50–300 kilometers of the GTP, with the distances away, are (see Appendix F, Figure 2-1):

- ANWR – Sensitive Class II Area (93 kilometers); and
- Gates of the Arctic National Park and Preserve – Sensitive Class II Area (214 kilometers).

Complete details of the ambient air quality, visibility, and deposition analyses at each of the areas is provided in Appendix F.

EPA's CALPUFF model was used to assess impacts at each of these areas. CALPUFF uses a prognostic meteorological input dataset. The most recent available dataset for the domain around the GTP is the three-year (2007–2009) WRF dataset developed for the Alaska North Slope by the Bureau of Ocean Energy Management. This dataset has been used for previous CALPUFF modeling on the North Slope and has been approved by the Bureau of Land Management for this region. The WRF modeling domain is a 620-kilometer by 450-kilometer grid centered on North Slope oilfields and pipeline corridor and encompassing each of the Sensitive Class II areas above. See Appendix F, Figure 6-1, for a location map.

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For cumulative impact analyses, the far-field modeling included existing sources and reasonably foreseeable development not close enough to the GTP to cause a significant concentration gradient. A total of 19 other facilities were included in the far-field modeling to account for these impacts. See Appendix F, Figure 4-1, for the locations of these facilities.

The NAAQS, AAAQS, and increment modeling results for ANWR and Gates of the Arctic National Park and Preserve are all well below the applicable standards. The most sensitive of these are the Class II increment analyses at these two areas. These results are provided in Tables 9.2.5-26 and 9.2.5-27, respectively, demonstrating that the GTP would not cause or contribute to a violation of the increments at Alaska Sensitive Class II areas. The remainder of the results are provided in Appendix F.

TABLE 9.2.5-26 Increment Analysis for the Gas Treatment Plant – ANWR				
Air Pollutant	Averaging Period	GTP Only Model-Predicted Concentration ($\mu\text{g}/\text{m}^3$)	Cumulative Analysis Model-Predicted Concentration ($\mu\text{g}/\text{m}^3$)	Class II Increments ($\mu\text{g}/\text{m}^3$)
Sulfur Dioxide	1-Hour ^a	NA	NA	NA
	3-Hour ^b	0.07	4.06	512
	24-Hour ^b	0.03	1.20	91
	Annual ^c	0.002	0.05	20
Nitrogen Dioxide	Annual ^c	0.02	0.36	25
Particulate Matter less than 10 Microns	24-Hour ^b	0.26	4.27	30
	Annual ^c	0.02	0.29	17
Particulate Matter less than 2.5 Microns	24-Hour ^b	0.27	4.49	9
	Annual ^c	0.02	0.29	4
Abbreviations: NA = not applicable $\mu\text{g}/\text{m}^3$ = micrograms per cubic meter Notes: ^a Neither USEPA nor ADEC have established increment thresholds for 1-hr NO ₂ , 1-hr SO ₂ , 1-hr CO, or 8-hr CO. ^b Value reported is the maximum of the highest-second-high values from each of the five modeled years. ^c Value reported is the maximum annual average concentration for the 5-year period.				

TABLE 9.2.5-27 Increment Analysis for the Gas Treatment Plant – Gates of the Arctic National Park and Preserve				
Air Pollutant	Averaging Period	GTP Only Model-Predicted Concentration ($\mu\text{g}/\text{m}^3$)	Cumulative Analysis Model-Predicted Concentration ($\mu\text{g}/\text{m}^3$)	Class II Increments ($\mu\text{g}/\text{m}^3$)
Sulfur Dioxide	1-Hour ^a	NA	NA	NA
	3-Hour ^b	0.03	0.20	512

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TABLE 9.2.5-27 Increment Analysis for the Gas Treatment Plant – Gates of the Arctic National Park and Preserve				
Air Pollutant	Averaging Period	GTP Only Model-Predicted Concentration (µg/m ³)	Cumulative Analysis Model-Predicted Concentration (µg/m ³)	Class II Increments (µg/m ³)
	24-Hour ^b	0.01	0.10	91
	Annual ^c	0.0004	0.003	20
Nitrogen Dioxide	Annual ^c	0.003	0.04	25
Particulate Matter less than 10 Microns	24-Hour ^b	0.19	1.58	30
	Annual ^c	0.01	0.08	17
Particulate Matter less than 2.5 Microns	24-Hour ^b	0.20	1.55	9
	Annual ^c	0.01	0.08	4
Abbreviations: NA = not applicable µg/m ³ = micrograms per cubic meter Notes: ^a Neither USEPA nor ADEC have established increment thresholds for 1-hr NO ₂ , 1-hr SO ₂ , 1-hr CO, or 8-hr CO. ^b Value reported is the maximum of the highest-second-high values from each of the five modeled years. ^c Value reported is the maximum annual average concentration for the 5-year period.				

For far-field AQRV analysis, regional haze impacts were modeled at ANWR and Gates of the Arctic National Park and Preserve using the CALPUFF model and the same domain and modeling inputs as the ambient air quality impact analyses. See Appendix F for complete details.

Regional haze impacts are estimated based on the change in light extinction. If the predicted change in light extinction due to Project sources is less than 5 percent, there is no concern. Furthermore, if the predicted change in light extinction due to Project and offsite sources is less than 10 percent, there is no concern. If modeled impacts are above either of these thresholds, further investigation may be warranted on a case-by-case basis in consultation with the relevant FLM.

TABLE 9.2.5-28 Regional Haze Results for the GTP Only					
Class II Area	Year	Number of Days with Extinction Above		8th Highest Change in Extinction (%)	Visibility Extinction Threshold for a Project (%)
		5%	10%		
ANWR	2007	4	1	3.0	5.0
	2008	15	0	5.5	5.0
	2009	4	1	4.5	5.0
Gates of the Arctic National Park and Preserve	2007	1	1	1.6	5.0
	2008	2	0	2.8	5.0
	2009	5	1	2.8	5.0

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TABLE 9.2.5-29 Cumulative Regional Haze Results for the Gas Treatment Plant and Offsite Sources					
Class II Area	Year	Number of Days with Extinction Above		8th Highest Change in Extinction (%)	Visibility Extinction Threshold for a Project (%)
		5%	10%		
ANWR	2007	142	88	38.7	10.0
	2008	197	131	71.3	10.0
	2009	162	122	49.3	10.0
Gates of the Arctic National Park and Preserve	2007	76	36	23.0	10.0
	2008	94	55	35.9	10.0
	2009	69	44	32.5	10.0

Table 9.2.5-28 demonstrates the GTP generally would not contribute to visibility impairments Sensitive Class II areas within 300 kilometers. Results for one year at ANWR are slightly above the screening threshold.

For the cumulative impact results presented in Table 9.2.5-29, modeled visibility impacts are above the screening criteria at ANWR and the Gates of the Arctic National Park and Preserve.

Deposition modeling at ANWR and Gates of the Arctic National Park and Preserve used the CALPUFF model, which is consistent with FLAG (2010) for far-field deposition analyses. CALPUFF deposition modeling is both complex and conservative— see Appendix F for details. The results compared to the Class I screening DATs are provided in Table 9.2.5-30. As shown in Table 9.2.5-30, sulfur deposition from the GTP has negligible effects on ANWR and the Gates of the Arctic National Park and Preserve and therefore cumulative sulfur deposition modeling was not conducted. GTP-only and cumulative nitrogen deposition is below the applicable DATs at Gates of the Arctic National Park and Preserve demonstrating there is no concern at this Sensitive Class II area. At ANWR, while cumulative nitrogen deposition is below the DAT, GTP-only N deposition is slightly above the DAT.

TABLE 9.2.5-30 Deposition Results for the Gas Treatment Plant Only					
Class II Area		Year	Sulfur Predicted Impact (kg/ha/yr)	Nitrogen Predicted Impact (kg/ha/yr)	Class I Deposition Analysis Thresholds (kg/ha/yr)
Arctic NWR	GTP Only	3-Year Max	0.0009	0.007	0.005
	Cumulative	3-Year Max	NA	0.107	0.125
Gates of the Arctic National Park and Preserve	GTP Only	3-Year Max	0.0003	0.002	0.005
	Cumulative	3-Year Max	NA	0.031	0.125

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Ozone and Secondary Particulate Matter Assessment

The Project reviewed the processes involved in the formation and loss of ozone and secondary PM_{2.5} to provide a qualitative assessment of the level of concern. The intent is to help with the understanding of the formation and loss processes in general, but also in relation to the specific characteristics of the Arctic atmosphere. A complete analysis is provided in Appendix F.

A review of available monitoring data near the Project area showed that neither ozone nor PM_{2.5} current concentrations are or have been in exceedance of the NAAQS/AAQS despite continual development on the North Slope. Furthermore, back trajectory analysis for selected episodes identified from the monitoring data suggest that observed concentrations could be, at least in part, the result of pollution transported from mid-latitude regions.

Using available tools, a conservative quantification of the potential regional impact of the GTP in both ozone and PM_{2.5} was developed. The information provided in this analysis is very conservative as it relies on photochemical modeling performed for the continental United States, which does not account for the chemical complexities (halogen chemistry), the seasonal pattern (photochemical shutdown in the winter) and the global boundary influences (long-range transport contribution to pollution from Asia and Europe) that is known to occur in Alaska.

The analysis in Appendix F indicates that emissions from the GTP would at most lead to ozone increments of about 7 ppbv. This increase is not additive, otherwise the cumulative effect of existing sources would have already affected the monitoring record. Also, the location of peak impact is likely to be variable in space and time. This maximum increase of 0.007 ppmv (7 ppbv) in a region where ozone design values currently range around 0.045 ppmv would not lead to non-attainment issues in the region.

For PM_{2.5}, the Appendix F analysis indicates that emissions from GTP would at most lead to nitrate increments of about 1 µg/m³ and sulfate increments of less than 8 µg/m³ for the 24-hour concentrations. Such PM_{2.5} impacts would not be expected to occur near the source, but downwind as the result of secondary formation. Just as with ozone this increase is not additive and the location of peak impact likely to be variable in space and time. This maximum increase of less than 10 µg/m³ in a region where PM_{2.5} concentrations range around 10 µg/m³ would not lead to non-attainment issues in the region. Furthermore, formation of ammonium sulfate and nitrate would be significantly limited by ammonia availability.

The assessment suggests there is little concern about formation of ozone and secondary PM_{2.5} as a result of operation of the GTP.

9.2.5.3 Non-jurisdictional Facilities

Operations emissions from PBU MGS project and new facilities are anticipated to be limited to insignificant sources associated with new valve module heating and fugitive emissions of organic compounds emitted from piping components and connectors. Rather, net PBU emissions would actually decrease once the PBU MGS project begins because PBU turbine capacity currently needed for gas re-injection would be reduced. Future PBU emissions from CGF and CCP under the PBU MGS project are summarized in Table 9.2.5-31. These emissions are the net change from baseline (i.e., the no action alternative) for the MGS build alternative. See Appendix G for more details.

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Operations emissions from the PTU Expansion project and new facilities are anticipated to be similar to current operating emission for the PTU Initial Production System (IPS) including natural gas production, and gas transportation. Like the PBU MGS project, PTU expansion emissions for the build alternative have been estimated and summarized in Table 9.2.5-31 as the net change in emissions from baseline (i.e., IPS with no gas expansion).

Kenai Spur Highway relocation project operation emissions are limited to assorted vehicle emissions that use the highway. However, relocation of the Kenai Spur Highway is not expected to have a material change in traffic emissions.

TABLE 9.2.5-31 Total Annual Operations Emissions for Non-Jurisdictional Facilities ^a							
Project Construction Year	tons/year						tonnes/year ^b
	VOC	NOx	CO	PM ₁₀	PM _{2.5}	SO ₂	CO _{2e}
Year 10	-17	-3,038	-415	-51	-51	-39	-784,058
Year 15	-35	-6,020	-811	-110	-110	-84	-1,740,665
Year 20	-51	-10,427	-1,236	-174	-174	-98	-2,661,040
Year 25	-62	-13,021	-1,420	-211	-211	-128	-3,260,432

^a Operations emissions are the net change from the baseline, which is the build alternative emissions less the no action alternative.
^b Annual emissions of GHGs are reported in metric tons (tonnes) per year.

9.2.6 Applicable Air Quality Regulatory Requirements – Operations

9.2.6.1 Summary of Federal and State Regulatory Requirements

This section provides an overview of applicable regulations and expected compliance requirements. Some of the more significant provisions are discussed in more detail in the subsequent sections.

The federal programs discussed below are implemented by ADEC, which is the regulatory agency for state-only programs. A summary of applicable regulations is provided for federal rules in Table 9.2.6-1 and for Alaska state regulations that are implemented by ADEC in Table 9.2.6-2.⁷

Note that the regulations identified in Tables 9.2.6-1 and 9.2.6-2 may apply at one Project site, but not another. For example, based on design information, the PSD rules would apply to permitting the LNG Plant and the GTP, but not other stationary sources.

⁷ This summary reflects the United States Supreme Court decision in *UARG v. EPA*, 573 U.S. ___ (2014) and the July 24, 2014, EPA Guidance indicating that EPA will no longer treat GHGs as an air pollutant for purposes of determining whether a source is a major source required to obtain a PSD or Title V permit. However, GHG emissions would trigger a BACT review under PSD if total annual emissions are 75,000 tons or more.

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TABLE 9.2.6-1 Federal Air Quality Regulations Potentially Applying to the Project – Operation		
Citation/Part of 40 C.F.R.	Title	Description
50	NAAQS	Modeling and any monitoring must comply with NAAQS.
51 Appendix W	Guideline on Air Quality Modeling	Dispersion modeling in support of permit applications must comply with this regulation.
§ 52.21	PSD Regulations	Applies to major stationary sources and modifications; see Section 9.2.6.2
58 Appendix E	Air Quality Monitoring	Applies for stationary sources that submit ambient air monitoring data in support of applications
60 Subpart A	General Provisions for NSPS	Includes general notifications, recordkeeping, reporting, and sampling requirements for affected units
§ 60.18	Flare compliance requirements	Includes flare design standards and monitoring requirements for flares used as NSPS emission control devices
60 Subpart Db	NSPS for boilers and heaters > 100 MMBtu/hr	Regulates NO _x , SO ₂ , PM emissions from boilers and heaters
60 Subpart Dc	NSPS for boilers and heaters > 10 MMBtu/hr	Standards for small boilers, generally regulating SO ₂ and PM emissions from oil (and solid fuel) fired units
60 Subpart Kb	NSPS for Tanks < 75 m ³	Can apply to tanks storing volatile organic liquids
60 Subpart IIII	NSPS for Compression Ignition Engines	Emissions limits, monitoring, testing requirements for diesel-fired engines based on use, horsepower, and engine sizes
60 Subpart JJJJ	NSPS for Spark Ignition Engines	Emissions limits, monitoring, testing requirements for spark-ignition natural gas-fired engines based on use, horsepower, and engine sizes.
60 Subpart KKKK	NSPS for Combustion Turbines including Supplemental Firing	Includes NO _x and SO ₂ limits for turbines > 10 MMBtu/hour heat rate, monitoring, testing, recordkeeping and reporting requirements
60 Subpart OOOOa	NSPS for Natural Gas Production and Transmission	Applies to onshore operations, including processing, transmission, and storage facilities. Contains monitoring, notification, recordkeeping and reporting requirements.
63 Subpart A	NESHAPs General Provisions	General compliance for listed sources of hazardous air pollutants, includes permitting requirements, monitoring, recordkeeping, reporting, and includes standards for flares used as NESHAPs emission control devices.
63 Subpart HH	NESHAP for oil and gas production facilities	Applies to VOC/HAP emission from major and area sources including glycol dehydration units, tanks and compressors. May be exempt based on liquid hydrocarbon production rates (<39,700 liter/day), (10,500 gal) and other factors.
63 Subpart HHH	NESHAP for natural gas transmission and storage	Applies to natural gas transmission and storage facilities, but only at sites with a glycol dehydration unit.
63 Subpart YYYY	NESHAPs for combustion turbines	Applies at major HAP sources, but not on the North Slope, except for notifications
63 Subpart ZZZZ	NESHAPs for stationary engines	Applies to RICE, including generator engines, emergency generator engines, firewater pump engines, etc. Compliance generally demonstrated by complying with NSPS Subparts IIII or JJJJ.
63 Subpart DDDDD	NESHAPs for Boilers and heaters at major sources	Applies to boilers and process heaters at major HAP sources. Natural gas fired units must conduct five-year tune-ups.
63 subpart CCCCCC	NESHAPs for Gasoline Dispensing Facilities	Applies to an onsite gasoline dispensing facility, with requirements based on monthly throughput.
68	Chemical Accident Prevention	Applies to stationary sources that have more than the threshold quantity of a regulated toxic or flammable substance.
71	Title V operating Permits	Major sources > 100 ton/year and certain NSPS and NESHAP

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TABLE 9.2.6-1 Federal Air Quality Regulations Potentially Applying to the Project – Operation		
Citation/Part of 40 C.F.R.	Title	Description
		sources must obtain an operating permit from ADEC.
80 Subpart I	ECA Marine Fuel Standards	May apply to end-users of marine fuel.
82	Stratospheric Ozone Protection	Applies to facilities with listed refrigerants, to manage and control emissions or releases from those units.
89	Non-road compression ignition engines	Applies to pre-2014 non-road compression-ignition engines, including portable units
91	Marine spark-ignition engines	May apply to specific marine spark-ignition engines
94	Marine compression-ignition engines	May apply to specific marine compression-ignition engines
98 Subparts A, C, and W	Mandatory GHG reporting rule	Sources with > 25,000 metric tons/year of CO ₂ e emissions must calculate and submit annual reports of GHG emissions.
1042	Marine compression-ignition engines	May apply to certain end-users of marine compression-ignition engines
1043	Control of Emissions under MARPOL	Controls NO _x , SO ₂ , and PM emissions from marine vessels subject to MARPOL Protocol.

TABLE 9.2.6-2 Alaska Air Quality Regulations Potentially Applying to the Project – Operation		
Citation to 18 AAC 50	Title	Description
50.010	Ambient air quality	Facility must be designed and permitted to operate in compliance with ambient air quality standards.
50.020	PSD Baseline dates and maximum allowable increases	Facility must be designed and permitted to operate in compliance with the PSD increments. PSD increments will be evaluated for LNG and GTP operation.
50.025	Visibility and other special protection areas	Establishes visibility protections for three areas, including (1) Mt. Deborah and the Alaska Range East, as viewed from approximately the Savage River Campground area, (2) Mt. McKinley, Alaska range, and Interior Lowlands as viewed from the vicinity of Wonder Lake, and (3) geographic areas classified as Class I under 18 AAC 50.15(c). This last group is also an area with federally enforceable visibility protection, but this provision allows ADEC to interpret and regulate visibility impacts under its own rules.
50.035 (a) (2)	Documents adopted by reference	Adopts the <i>Workbook for Plume Visual Impact Screening and Analysis (Revised)</i> EPA 454/R-92-023, October 1992 as a means of addressing visibility impacts.
50.040 (a)	New Source Performance Standards	Adopts the Federal New Source Performance Standards, including Subpart A general provisions, Subpart IIII for compression ignition reciprocating internal combustion engines, Subpart JJJJ for spark ignition reciprocating internal combustion engines, Subpart KKKK for stationary combustion turbines, and Subpart OOOO for natural gas production and transmission.
50.040(c)	National Emission Standards for Hazardous Air Pollutants	Adopts the Federal National Emission Standards for Hazardous Air Pollutants, including the Subpart A for general provisions, Subpart YYYYY for stationary combustion turbines, Subpart ZZZZ for stationary reciprocating internal combustion engines, and Subpart DDDDD for industrial, commercial, and institutional boilers and process heaters located at major HAP sources.
50.045 (d)	Prohibitions	A person who causes or permits bulk materials to be handled,

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TABLE 9.2.6-2 Alaska Air Quality Regulations Potentially Applying to the Project – Operation		
Citation to 18 AAC 50	Title	Description
		transported, or stored, or who engages in any industrial activity or construction project shall take reasonable precautions to prevent particulate matter from being emitted into the ambient air. No specific permitting or approval for compliance is required; however, the agency may take action if this provision is violated, particularly in response to a complaint by the general public.
50.050	Incinerator emission standards	Requires opacity to be 20 percent or less averaged over any six consecutive minutes. No limit exists for particulate matter emissions for incinerators that have a rated capacity less than 1,000 pounds per hour. Project design indicates that no incinerators will exceed that design threshold, but if rated capacity is above that level, the PM emission standards would apply.
50.055	Industrial Processes and fuel burning equipment	This rule limits visible emissions from industrial process or fuel-burning equipment to 20 percent or less for any consecutive six-minute period. Particulate matter emissions from fuel-burning equipment also must comply with grain loading standards in § (b) of the regulation. Sulfur compound emissions from an industrial process or fuel-burning equipment may not exceed 500 ppm averaged over three hours.
50.070	Marine Vessel visible emission standards	Establishes marine vessel visible emission standards and would apply to marine vessels that are used in support of construction both of the pipeline across Cook Inlet and of the LNG terminal facilities. Specific visibility standards apply to these vessels.
50.080	Ice fog standards	Allows ADEC to require a permit to reduce water vapor emissions for fuel burning equipment or an incinerator in areas of potential ice fog
50.100	Non-road engines	Specifies that the emissions from non-road engines (heavy equipment, portable generators, and any engines that are temporary) are not included when determining the classification of a stationary source or modification for a permit.
50.110	Air pollution prohibited	ADEC can restrict emissions which may be injurious to health, welfare, property or unreasonably interfere with the enjoyment of life or property. Construction activities that may cause excessive dust, particularly near residences or sensitive receptors, may be curtailed under this regulation if a complaint is received and ADEC considers the impacts to be within these adverse determinations.
50.215	Ambient air quality analysis methods	Provides methods for analyzing (or modeling) ambient air quality impacts for permitting.
50.220	Test methods	References test methods for demonstrating compliance with emission limits.
50.225	Owner requested limits	Operators and owners can request emission limits that limit applicability of other air quality regulations.
50.235	Unavoidable emergencies	Establishes rules for reporting and responding to emergencies related to air pollution
50.240	Excess emissions	Provides requirements for reporting excess emissions including startup and shutdown.
50.245 and 50.246	Air Quality episodes	Allows ADEC to declare an air quality episode based on actual or potential impacts, and subsequently request voluntary reductions in emissions from stationary sources.
50.306	Prevention of Significant	Applies to major stationary sources for construction. Applies to

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TABLE 9.2.6-2 Alaska Air Quality Regulations Potentially Applying to the Project – Operation		
Citation to 18 AAC 50	Title	Description
	Deterioration (PSD) Permits	LNG at GTP based on preliminary data.
50.316	Preconstruction review for major source of HAPs	Provides ADEC review of federal standards under 40 C.F.R. Part 63 (Maximum Achievable Control Technology Standards). Includes obtaining a permit from ADEC.
50.326	Title V operating permits	Sources with emissions of 100 tons/year or greater of any regulated criteria pollutant (not GHG) must obtain an operating permit, renewable on a five-year basis, and when new applicable requirements affect the source.
50.345 50.346	Construction minor and operating permits standard permit conditions	Compliance requirements (standard conditions) for PSD, Title V operating, and minor sources permits and for modifications to existing stationary sources. Includes requirements for notifications, document submittals, and inventory reporting.
50.400 - 50.499	User Fees	Establishes fee schedules for permits and permit renewals
50.502	Minor construction permits	Specifies provisions for requiring a minor source construction permit for certain activity, based on the potential emissions from a stationary source or modification. Certain components of the construction activity may qualify as a stationary source depending on the duration of activity at a specific location. Minor permits must be obtained for the following potential activities under §(b) of this regulation: (1) An asphalt plant with a rated capacity of at least 5 tons/hour of product (2) A rock crusher with a rated capacity of 5 tons/hour (3) One or more incinerators with a cumulative rated capacity of 1,000 lbs./hour or more
50.508	Minor permits requested by owner or operator	Owner or operator can establish enforceable emission limits in a permit to avoid applicability of specific regulations
50.540	Minor Permits	A minor source construction permit is required based on potential emissions.
50.544	Minor permits: content	Requires permit conditions for minor sources
50.990	Definitions	Provides regulatory definitions for air quality regulations. Should be consulted in reviewing permit and compliance requirements, including any changes or modifications.

9.2.6.2 New Source Review (NSR) and Prevention of Significant Deterioration (PSD)

Ambient air quality is protected in part by an air quality permitting program for new stationary sources and modifications to existing stationary sources. This program is implemented by ADEC and addresses the federal NSR regulations, as well as state regulations. Separate programs are in place to issue permits for major and minor stationary sources. The federal NSR program for major sources consists of rules for issuing preconstruction permits for attainment area pollutants (known as the PSD rules) and non-attainment area pollutants (known as the non-attainment NSR rules). The Project would be located in areas that are in attainment with, or unclassified with respect to, the ambient standards for all pollutants. As a result, only PSD would apply for permitting major stationary sources within the Project. EPA has approved the Alaska PSD rules as an element of the SIP allowing ADEC to implement PSD (see 18 AAC 50.306 and 40 C.F.R. § 52.21).

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A stationary source is a “major source” if the source’s potential to emit, which is its capability at maximum design capacity to emit a pollutant, except as constrained by federally enforceable permit conditions, exceeds certain emission thresholds. Under the PSD rules, a major stationary source is one that emits or has the potential to emit:

- For a categorical list of 28 sources (40 C.F.R. § 52.21[b][1][i][a]), 100 tons per year or more of any regulated air contaminant (other than GHGs) in an area designated attainment for that air contaminant; or
- For other sources, 250 tons per year or more of any regulated air contaminant (other than GHGs) in an area designated attainment for that air contaminant.

The stationary sources proposed as part of the Project are not included on the categorical list and so 250 tons per year is the threshold for determining major source status under PSD for all criteria pollutants for new sources installed as part of the Project.

If a new source or modification is “major,” PSD review and permitting is required for associated regulated pollutants emitted in amounts equal to or greater than the applicable “significance levels.” The PSD significance levels are specified in 40 C.F.R. § 52.21(b) (23) (i) as follows: 40 tons per year for NO_x, SO₂, and VOCs; 100 tons per year for CO; 15 tons per year for PM₁₀; 10 tons per year for PM_{2.5}; and 0.6 tons per year for lead. PSD applicability for some pollutants can also be triggered by other pollutant emissions. For instance, PM_{2.5} PSD applicability can be triggered by significant emissions of NO_x or SO₂, and ozone PSD applicability can be triggered by significant emissions of NO_x. Formation of ozone and secondary particulate matter (PM_{2.5}) can be addressed qualitatively.

GHG emissions may be regulated if the stationary source triggers PSD applicability through other pollutants and the total CO₂e emissions (or increase) are above 75,000 tons per year⁸. CO₂e emissions are defined as the sum of the mass emissions of each individual GHG adjusted using the applicable GWP for the following six gases:

- CO₂;
- Nitrous oxide (N₂O);
- Methane (CH₄);
- Hydrofluorocarbons;
- Perfluorocarbons; and
- Sulfur hexafluoride.

Based on the information provided in Section 9.2.5, both the LNG Plant and the GTP would be major sources subject to PSD review. An applicability summary is provided in Table 9.2.6-3 based on Project information. Compressor stations are not included in the list of 28 sources provided in 40 C.F.R. §

⁸ EPA is undertaking rulemaking regarding the threshold for applying PSD to GHGs; however, any changes would not be expected to impact permitting for the Project.

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52.21[b][1][i][a]), so are not considered major sources subject to PSD review for the Project because their total annual potential emissions of any criteria air pollutant are below 250 tons per year.

TABLE 9.2.6-3 y PSD Applicability for the Liquefaction Facility and GTP – Operation				
Pollutant	Liquefaction Facility Potential to Emit (tons per year)	LF PSD	GTP Potential to Emit (tons per year)	GTP PSD
Nitrogen Oxides (NO _x)	1,170	Yes	2,231	Yes
Carbon Monoxide (CO)	1,728	Yes	2,073	Yes
Volatile Organic Compounds (VOCs)	195	Yes	304	Yes
Particulate Matter (PM ₁₀)	259	Yes	263	Yes
Particulate Matter (PM _{2.5})	259	Yes	263	Yes
Sulfur Dioxide (SO ₂)	90	Yes	99 ^b	Yes
Lead (Pb)	TBD	TBD	TBD	TBD
Total GHG Emissions (CO ₂ e) ^a	3,846,143	Yes	4,196,914	Yes
^a GHG are reported in metric tons (tonnes) per year. ^b Value based on 15 ppmv sulfur in the fuel gas which is representative of permitted long-term, normal operations. For a short-period of time during facility commissioning, the sulfur content of the fuel gas will be 90 ppmv sulfur in the fuel gas which is not expected to become an enforceable permit limit applicable to long-term, normal operations.				

If PSD review applies, a PSD permit application must address the following requirements:

- Apply Best Available Control Technology (BACT) for each regulated pollutant for which the new stationary source or major modification would result in a significant net emissions increase (40 C.F.R. § 52.21[j][3]);
- Conduct an air quality impact analysis that establishes the maximum modeled impact and demonstrates emissions associated with the proposed new source or modification, in conjunction with all other emission increases and decreases, will not cause or contribute to violations of any NAAQS or allowable PSD increment (40 C.F.R. § 52.21[k]);
- Provide an ambient air analysis based on current data collected in the vicinity of the Project (§ 52.21[m]);
- Provide an analysis of the impairment to visibility, soils, and vegetation that would occur as a result of the stationary source and general commercial, industrial, residential, and other growth associated with the stationary source (40 C.F.R. § 52.21[o][1]);
- Provide an analysis of the projected additional air quality impact as a result of general commercial, industrial, residential, and other growth associated with the stationary source (40 C.F.R. § 52.21[o][2]); and

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- Provide an analysis of the impacts to air quality and air quality-related values at nearby Class I areas (40 C.F.R. § 52.21[p]), if applicable.

9.2.6.3 Preconstruction Review of Major Sources of Hazardous Air Pollutants

Stationary sources that emit more than 10 tons per year of a single HAP or 25 tons per year of all HAPs combined are classified as major sources under 40 C.F.R. 63.2. Major HAP sources are required by 40 C.F.R. 63.5 to obtain a permit prior to construction. The construction permit required by major HAP sources is administered by ADEC under a SIP-approved program through 18 AAC 50.316.

Based on the information provided in Section 9.2.5 above, both the LNG Plant and the GTP would be major HAP sources subject to preconstruction review. An applicability summary is provided in Table 9.2.6-4, based on preliminary Project information. Based on the information provided in Section 9.2.5, the compressor stations would not be major HAP sources. As a result, a preconstruction review is not required for those facilities.

TABLE 9.2.6-4 Preliminary HAP-Major Applicability for the Liquefaction Facility and GTP – Operation				
Pollutant	Liquefaction Facility Potential to Emit (tons per year)	LF HAP Major	GTP Potential to Emit (tons per year)	GTP HAP Major
Largest Individual Hazardous Air Pollutant (Formaldehyde)	25.8	Yes	25.8	Yes
Total Hazardous Air Pollutants (HAPs)	37.7	Yes	42.4	Yes

Under the HAP-major preconstruction review rules, a major HAP source must implement the maximum achievable control technology (MACT) as determined in the applicable subparts of 40 C.F.R. 63. Further information about applicable NESHAPs subparts (40 C.F.R. 63) is provided in Section 9.2.6.7.

9.2.6.4 Minor New Source Review Permits

For new stationary sources, a minor permit is required under 18 AAC 50.502(c) (1) if (1) the source is not a major source, and (2) the potential to emit one or more criteria pollutants exceeds the following:

- 15 tons per year of PM₁₀;
- 40 tons per year NO_x;
- 40 tons per year of SO₂;
- 0.6 tons per year of Pb;
- 100 tons per year of CO within 10 kilometers of a CO non-attainment area; or
- 10 tons per year of direct PM_{2.5}.

Based on the information provided in Section 9.2.5, none of the compressor or heater stations would be major stationary sources subject to PSD, but all compressor and heater stations would be subject to minor NSR permitting. Therefore, these sources require minor source permits from ADEC prior to beginning construction.

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At this time, no minor NSR permits have been identified for construction sources. A final determination would be made after construction contractors are selected.

9.2.6.5 Title V Operating Permits

Title V of the CAA requires that sources that either emit more than 100 tons per year of any criteria air pollutant or are subject to certain NSPS or NESHAP subparts obtain an operating permit under this rule. ADEC is responsible for issuing operating permits in Alaska pursuant to 18 AAC 50.326. A new source must submit a complete application for an operating permit within 12 months after the start of operation.

Based on information available at this time, the Liquefaction Facility, GTP, and all compressor and heater stations would each be required to obtain a Title V permit.

9.2.6.6 New Source Performance Standards (NSPS)

Pursuant to Section 111 of the CAA, EPA promulgates NSPS, codified in 40 C.F.R. Part 60, for certain newly constructed, modified, or reconstructed sources of emissions of criteria pollutants. These standards are based on best demonstrated technology for air pollution control of specified equipment and may be expressed as numerical emission limits, performance standards, or work practices. Subpart A of Part 60 establishes general provisions for sources subject to the various NSPS subparts, including general performance testing, monitoring, notification, reporting, and recordkeeping requirements.

Table 9.2.6-5 provides a summary of the NSPS categories under 40 C.F.R. 60 that are potentially applicable to emission units included in the Project. Further details regarding applicability and requirements are provided in Appendix H. Final NSPS applicability determinations would be made after construction contractors are selected.

TABLE 9.2.6-5 Preliminary NSPS Applicability Summary for Operations			
NSPS Subpart	Applicability		
	Liquefaction Facility	Compressor and Heater Stations	GTP
Subpart A – General Provisions	Yes	Yes	Yes
Subpart Da – Electric Utility Steam Generation Units	No	No	No
Subpart Db – Industrial, Commercial, and Institutional Steam Generating Units	No	No	Yes
Subpart Dc – Small Industrial, Commercial, and Institutional Steam Generating Units	No	Yes	No
Subpart Kb – Volatile Organic Liquid Storage Vessels	TBD	No	TBD
Subpart CCCC – Commercial and Industrial Solid Waste Incineration Units	No	Yes	No
Subpart IIII – Stationary Compression Ignition Internal Combustion Engines	Yes	No	Yes
Subpart JJJJ – Stationary Spark Ignition Internal Combustion Engines	No	Yes	No
Subpart KKKK – Stationary Combustion Turbines	Yes	Yes	Yes

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TABLE 9.2.6-5 Preliminary NSPS Applicability Summary for Operations			
NSPS Subpart	Applicability		
	Liquefaction Facility	Compressor and Heater Stations	GTP
Subpart OOOOa – Crude Oil and Natural Gas Production, Transmission and Distribution	Yes	Yes	Yes

9.2.6.7 National Emission Standards for Hazardous Air Pollutants (NESHAPs)

The 1970 CAA required that the EPA develop health risk-based standards for regulating HAP emissions. These regulations are codified in 40 C.F.R. Part 61, National Emission Standards for Hazardous Air Pollutants (NESHAPs) and apply to specific pollutants and source categories. The Project is not one of the source categories regulated under 40 C.F.R. Part 61 and, as such, the requirements of 40 C.F.R. 61 do not apply to the Project.

The 1990 CAA Amendments expanded EPA obligation to regulate HAPs and required EPA to set technology-based standards for a larger list of HAPs and for many more source categories. These NESHAPs are codified in 40 C.F.R. Part 63, also referred to as MACT standards, and regulate HAP emissions from major sources of HAPs and area sources of HAPs within specific source categories. Part 63 defines a major source of HAPs as any stationary source or group of stationary sources located within a contiguous area and under common control that has the potential to emit more than 10 tons per year of any single HAP or more than 25 tons per year of all HAPs combined. Part 63 defines an area source of HAPs as any stationary source of HAPs that is not a major source of HAPs. Preliminary HAPs emission calculations indicate that the Liquefaction Facility and the GTP are each anticipated to have the potential to emit a single HAP, formaldehyde (which is formed by chemical reaction of the products of combustion), at a rate greater than 10 tons per year. As a result, these facilities are expected to be major sources of HAPs. The compressor stations, heater stations, and metering station potential to emit total HAPs and any single HAP would be below the 25 tons per year and 10 tons per year thresholds, respectively, and would be classified as area sources of HAPs.

Subpart A of Part 63 provides the general provisions of the MACT standards, which includes monitoring, notification, and reporting requirements for sources subject to certain subparts within 40 C.F.R. Part 63. Each subpart provides a table identifying which general provisions apply to that subpart. Table 9.2.6-6 provides a summary of the MACT standards in 40 C.F.R. Part 63 that may apply to the proposed Project facilities. Further details regarding applicability and requirements are provided in Appendix H. Final NESHAPs applicability determinations would be made after construction contractors are selected.

TABLE 9.2.6-6 Preliminary NESHAPs Applicability Summary for Operations			
NESHAPs Subpart	Applicability		
	LNG Plant	Compressor and Heater Stations	GTP
Subpart A – General Provisions	Yes	Yes	Yes

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Subpart Y – National Emission Standards for Marine Tank Vessel Loading Operations	No	No	No
Subpart EEE – NESHAPs from Hazardous Waste Combustors	No	TBD	No
Subpart EEEE – NESHAPs for Organic Liquids Distribution (Non-Gasoline)	TBD	No	TBD
Subpart H – Organic HAPs for Equipment Leaks	TBD	TBD	TBD
Subpart HH – NESHAPs for Oil and Natural Gas Production Facilities	TBD	No	TBD
Subpart HHH – NESHAPs for Natural Gas Transmission and Storage Facilities	No	No	Yes
Subpart YYYY – NESHAPs for Stationary Combustion Turbines	Yes	No	Yes
Subpart ZZZZ – NESHAPs for Stationary Reciprocating Internal Combustion Engines	Yes	Yes	Yes
Subpart DDDDD – NESHAPs for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters	No	No	Yes
Subpart JJJJJ – NESHAPs for Industrial, Commercial, and Institutional Boilers Area Sources	No	No	No

9.2.6.8 Chemical Accident Prevention (40 C.F.R. 68)

Section 112(r) of the 1990 CAA Amendments requires the EPA to publish regulations and guidance for chemical accident prevention at facilities for substances that pose the greatest risk of harm from accidental releases. The chemical accident prevention provisions, also referred to as the Risk Management Program (RMP), are codified in 40 C.F.R. Part 68. The regulations include a list of regulated substances that include methane, propane, and ethylene. The regulation also includes threshold quantities (TQs) for determining applicability to stationary sources. If a stationary source stores, handles, or processes one or more regulated substances in a quantity equal to or greater than the TQ as determined per 40 C.F.R. 68.115, the facility must prepare and submit a risk management plan to the EPA.

A preliminary RMP applicability analysis that may apply to the proposed Project facilities is summarized in Table 9.2.6-7. See Appendix H for further details. Final applicability determinations would be made based on final facility design.

TABLE 9.2.6-7 Preliminary RMP Applicability Summary			
40 C.F.R. Part 68 - Chemical Accident Prevention Provisions	Applicability		
	Liquefaction Facility	Compressor and Heater Stations	GTP
Subpart F – Regulated Substances for Accidental Release Prevention	No	No	Yes

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9.2.6.9 The Federal Greenhouse Gas Reporting Rule

EPA's Greenhouse Gas Monitoring Recordkeeping and Reporting Rule (40 C.F.R. Part 98) requires reporting of GHG emissions from suppliers of fossil fuels or industrial GHGs, manufacturers of vehicles and engines, and facilities that emit greater than or equal to 25,000 metric tons of GHG (as CO₂e) per year. As set forth in Section 9.2.5, the potential CO₂e emissions from operation of the Liquefaction Facility, GTP, compressor stations, and heater station would all exceed 25,000 tonnes per year; therefore, they would all be subject to the GHG reporting rule. Additionally, construction of the Liquefaction Facility, GTP, and possibly Mainline could also exceed 25,000 tonnes per year, triggering GHG reporting requirements.

Reporting would be required for the first year of operation or construction that exceeds 25,000 tonnes per year. A report needs to be submitted on EPA's electronic database by March 31 of each year for the previous calendar year's emissions. Reporting is not required for construction activities from portable equipment unless stationary sources (e.g., heaters, compressors, engines) have combined emissions above 25,000 tons per year and are at the same location for 12 consecutive months.

9.2.6.10 General Conformity with Non-Attainment SIPs

Promulgated under 40 C.F.R. Part 51 Subpart W and 40 C.F.R. Part 93 Subpart B, the General Conformity Rule is used to determine if non-transportation-related federal actions meet the requirements of the CAA and the applicable SIP by ensuring that air emissions related to the action do not cause or contribute to new violations of a NAAQS or increase the frequency or severity of any existing violation of a NAAQS or interim emission reduction. A General Conformity Determination is required for federally sponsored or federally approved actions in non-attainment areas, or in certain maintenance areas, when the total direct and indirect net emissions of non-attainment pollutants (or their precursors) exceed specified thresholds (40 C.F.R. § 93.153). This regulation ensures federal actions conform to the SIP and state attainment plans.

A complete analysis of general conformity is provided in Appendix M. To summarize, Project representatives reviewed air pollutant emissions associated with Project activities that would be emitted within air quality non-attainment areas or maintenance areas identified in Table 9.2.6-8.

TABLE 9.2.6-8 Non-Attainment and Maintenance Areas in the Project Vicinity	
Area	Relevant Emissions Type
Fairbanks North Star Borough 2006 PM _{2.5} Non-attainment Area	PM _{2.5} emissions and PM _{2.5} precursors (SO ₂ and NO _x)
Fairbanks Area CO Maintenance Area (including the Fairbanks and Fort Wainwright portion and the North Pole portion of the Maintenance Area)	Carbon Monoxide
Municipality of Anchorage CO Maintenance Area	Carbon Monoxide
Eagle River PM ₁₀ Maintenance Area	PM ₁₀

Relevant emissions would result from Project transportation/logistics activities that occur within specific non-attainment or maintenance areas and from a pipeline construction support facility that may be located

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in Fairbanks during Project construction. Neither Project physical construction activities nor facility operations would occur within any of the areas listed in Table 9.2.6-8.

Under Section 93.153(b) of the General Conformity rule, a conformity determination is required for each criteria pollutant or precursor where the total of direct and indirect emissions of the pollutant or precursor would equal or exceed specified “de minimis” emissions levels. For PM_{2.5} nonattainment areas, CO maintenance areas, and PM₁₀ maintenance areas, Section 93.153(b)(1) and (2) specifies that the de minimis emissions level for the relevant pollutants is 100 tons per year.

Table 9.2.6-9 summarizes the peak annual emissions for relevant pollutants or precursors expected to occur within each nonattainment or maintenance area within Alaska that potentially could be affected by the proposed Project.

TABLE 9.2.6-9 Applicability of General Conformity to Project Emissions			
Area	Relevant Emissions Type	Direct/Indirect Project Emissions (tons per year)	Does General Conformity Apply?
Fairbanks North Star Borough 2006 PM _{2.5} Nonattainment Area	PM _{2.5} emissions and PM _{2.5} precursors (SO ₂ and NO _x)	3.55 tons PM _{2.5} /year 5.46 tons NO _x /year 0.014 tons SO ₂ /year	No No No
Fairbanks Area CO Maintenance Area (including the Fairbanks and Fort Wainwright portion and the North Pole portion of the Maintenance Area)	Carbon Monoxide	1.90 tons CO/year	No
Municipality of Anchorage CO Maintenance Area	Carbon Monoxide	0.37 tons CO/year	No
Eagle River PM ₁₀ Maintenance Area	PM ₁₀	0.01 tons PM ₁₀ /year	No

As can be seen in Table 9.2.6-9, emissions for each pollutant or precursor is far below the 100 tons per year de minimis emissions threshold. Therefore, as specified in 40 C.F.R. 93.153(c)(1), the General Conformity provisions of 40 C.F.R. 93, Subpart B do not apply to federal approvals required for the Project. See Appendix M for complete details.

9.2.6.11 Federal Marine Vessel Regulations

Several regulations could potentially apply to marine vessel emissions ranging from small service vessels to oceangoing vessels. Emission standards and certification requirements are provided in 40 C.F.R. Parts 89, 94, and 1042, based on engine size and date of manufacture. Emissions from Project-operated vessels and carriers are based on assumptions about fleet engine sizes and dates of manufacture. General compliance provisions are provided in 40 C.F.R. Part 1068 with further regulations in 40 C.F.R. Part 1043 related to implementing MARPOL Protocol for in-use fuels.

9.2.6.12 Regional Haze Rule

The federally mandated Regional Haze Rule (40 C.F.R. 51 Subpart P) establishes regulations to improve and protect visibility in designated Class I areas (see Section 9.2.2.2). For new sources, the program is

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implemented through 40 C.F.R. Subpart P §53.307 as part of the existing NSR Program for major stationary sources and major modifications.

The EPA adopted the Regional Haze Rule to protect visibility in Class I areas. The rule lays out the specific requirements to ensure improvements in visibility in the DNPP and other large national parks and wilderness areas across the country through the mitigation of human-caused air pollution impacts. The Regional Haze Plan describes how the State of Alaska will meet federal requirements to measure and monitor visibility, aerosols, and air pollution at Alaska’s four Class I areas, how Alaska will evaluate the factors reducing visibility at each site, and how Alaska plans to identify and implement air pollution control measures on a case-by-case basis to reach natural visibility conditions by the 2064 Regional Haze Rule target date. There are no applicable requirements for the proposed facilities beyond the AQRV analyses that may be required for the PSD sources in the Project.

ADEC is required to notify the appropriate FLM of any proposed PSD major project that has the potential to impact a Class I area (generally within 62 miles [100 kilometers] of the Class I area). This notification must include an analysis of the project’s impact on visibility in the Class I area. Impacts are assessed to ensure continued “reasonable further progress” toward attaining visibility goals in the Class I areas. Compliance can require visibility monitoring as well as the imposition of control technologies based on cost and other factors. Analyses would generally be completed as part of the PSD application.

9.2.7 Construction Regulatory Compliance and Mitigation Measures

Air quality impacts would be minimized through the use of construction equipment that is compliant with applicable NSPS, NESHAPs, and other emission standards. Impacts may also be minimized through such means as best management practices (BMPs) for construction, optimization of site layouts, and efficiency assessments of electric power and process heat uses.

The Project *Construction Emissions Control Plan* would discuss BMPs for how construction practices would comply with applicable requirements. A template is provided in Appendix I. Other construction mitigation plans are the Project *Fugitive Dust Control Plan* (Appendix J) and the Project *Open Burning Plan* (Appendix K). Each of these plans would be used to identify controls and BMPs for applicable construction equipment and construction activities. Site/activity-specific plans won’t be able to be developed until construction contractors are appointed, and completed versions the referenced appendix plans would be provided at that time.

9.2.8 Operational Regulatory Compliance and Mitigation Measures

As set forth in Section 9.2.5, modeling analyses of the Liquefaction Facility, compressor stations, and GTP have not identified any instances where facility operations would not comply with applicable ambient air quality standards.

Air quality impacts would be minimized through the use of turbines and generators that are compliant with applicable NSPS, NESHAPs, and BACT determinations. Facilities impacts may also be minimized through such means as optimization of Project design parameters such as stack heights, building heights (which affect downwash), and efficiency assessments of electric power and process heat uses.

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A *Project Operations Emission Control Plan* would be developed that sets forth how facilities would ensure compliance with applicable requirements. The Table of Contents provided in Appendix L reflects annotated sections to be addressed in the full Plan developed during the Project permitting phase

9.2.9 Greenhouse Gas (GHG) Impacts and Mitigation Measures

Observations of climate trends in Alaska and the Arctic region have been well documented in recent years. There are many causes of global climate change, and the nature of climate change is affected by complex interactions within the earth-atmosphere-ocean system. Many of these causes are undergoing extensive research, and the results of these studies may play a role in developing a deeper understanding of global climate change and its relation to local emissions.

9.2.9.1 GHG Emissions Quantification

The GHG emissions associated with the Project are calculated and summarized in Sections 9.2.3 and 9.2.5, along with other air quality emissions, and the analysis includes both construction and operating activities. The information in Tables 9.2.9-1 and 9.2.9-2 includes emissions from construction and operation of jurisdictional facilities and non-jurisdictional connected actions.

TABLE 9.2.9-1									
Total GHG Emissions from Construction (CO ₂ e, tonnes)									
Year	Liquefaction Facility	Pipeline Spread 1	Pipeline Spread 2	Pipeline Spread 3	Pipeline Spread 4	PTTL	GTP & PBTL	NJF ^a	Totals
1							6,897	1,384	8,281
2	28,534	12,212	26,782	21,664	15,327		50,110	7,490	162,119
3	46,077	37,971	43,885	53,448	21,130	15,279	49,861	73,827	341,478
4	158,307	38,658	26,041	33,030	74,543	21,877	45,462	139,301	537,219
5	170,477	68,321	69,744	68,158	261,141	0	58,961	310,684	1,007,486
6	83,941	57,717	46,861	31,419	36,487	352	61,684	358,659	676,768
7	64,595	8,994	3,201	2,958	1,463		55,536	355,720	492,467
8	42,951						32,979	137,732	213,662
9	27,043						11,475	50,859	89,377
Total	621,925	223,873	216,514	210,677	410,091	37,508	372,965	1,435,654	3,528,855

^a NJF = non-jurisdictional facilities

TABLE 9.2.9-2	
Annual GHG Emissions from Operations	
Facility	CO ₂ e (tonnes per year)
LNG Plant and Marine Terminal	3,850,732
LNG Carriers and Support Tugs	81,248
Compressor and Heater Stations	1,722,921
Gas Treatment Plant	4,201,860
Pipeline Fugitives	346

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TABLE 9.2.9-2 Annual GHG Emissions from Operations	
Facility	CO ₂ e (tonnes per year)
Non-Jurisdictional Facilities (Year 10)	-784,058
Total GHG Emissions (CO₂e)^a	9,073,049
^a The total GHG emissions are calculated as CO ₂ equivalent (CO ₂ e) emissions, i.e., the sum of individual GHGs with the annual tons of each gas multiplied by its Global Warming Potential (GWP) relative to CO ₂ .	

9.2.9.2 Potential Impacts

While the GHG emissions from a single project can be estimated with an acceptable level of confidence, the potential influence of those GHG emissions on global climate change is not measurable with an acceptable level of confidence and, therefore, is not addressed in this Resource Report. The increased availability of natural gas in the world market (and potentially within Alaska) is likely to replace current use or displace future use of some higher-carbon fossil fuels, thereby resulting in an overall reduction in global GHG emissions. However, the extent to which air quality, GHG emissions, and climate might be improved through this replacement cannot be quantified at this time⁹. Estimates for GHG emissions from jurisdictional and non-jurisdictional connected actions are provided in Table 9.2.9-1.

9.2.9.3 Mitigation Measures

Generally, mitigation measures include unit fuel combustion efficiency, management of flaring and venting, protocols for reducing and minimizing fugitive leaks of methane from the pipeline system, and management of construction and maintenance operations to minimize overall GHG emissions.

9.3 NOISE

This section describes the existing baseline noise environment of the Project area and assesses potential noise impacts from Project construction and operation. The information provided relates to the human environment. Potential noise impacts on fish, wildlife, and marine mammals are addressed in Resource Report No. 3.

⁹ For comparison, EPA emission factors for CO₂ are 53.06 kg/mmBtu of natural gas, 73.96 kg/mmBtu of #2 fuel oil, and 95.52 kg/mmBtu for thermal coal. See 40 CFR 98, Subpart C, Table C-1. Thus, #2 fuel oil produces about 40% more CO₂ than natural gas and coal produces about 80 percent more CO₂ than natural gas. (EPA, 2009b).

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9.3.1 Existing (Baseline) Noise Levels

The majority of the Project area is located in undeveloped, sparsely populated areas; therefore, existing ambient noise levels are anticipated to generally be low. However, portions of the Project are located in residential or commercial areas or near highways, where ambient noise levels are expected to be higher.

9.3.1.1 Noise-Sensitive Areas

The FERC National Environmental Policy Act (NEPA) review generally evaluates noise generated by a project at noise-sensitive areas (NSAs), which include such receptors as residences, schools, hospitals, churches, playgrounds, farms, and camping facilities. The evaluation includes description of existing noise levels at the nearest NSAs and estimated impacts associated with Project construction and operations noise. Existing noise levels can be developed using either an estimate of the noise levels for land use types or a field survey measurement of existing noise levels. Field surveys determine existing ambient outdoor sound level measurements and document observed or measured factors, including meteorological conditions and witnessed or perceived sources of natural and manmade sounds, which describe the preexisting outdoor ambient sound environment at NSAs prior to Project construction and operation. Impact assessment of projected noise using an environmental sound level assessment for Project facilities includes developing a model to estimate the sound level contribution level from the facility at the nearest existing NSAs, assessing the far-field community sound levels at the identified NSAs for Facility construction and normal full load operation, and identifying the noise mitigation measures required to comply with the environmental sound level criterion stipulated by FERC of an Ldn of 55 dBA (see Section 9.3.5). This sound level is based on EPA's published Information on Levels of Environmental Noise Requisite to Protect Public Health and Welfare with an Adequate Margin of Safety. The EPA determined that an Ldn of 55 dBA protects the public from indoor and outdoor activity noise interference.

A survey of NSAs was conducted in vicinity of the Project. Table 9.3.1-1 provides a summary of the proximity of NSAs to various primary long-term noise generating facilities and possible buried trenchless locations during construction along with an analysis of NSA proximity to the Project.

TABLE 9.3.1-1 Identified NSAs Near Project Facilities and Buried Trenchless Locations					
Noise Source	MP	Identified NSAs within 1 Mile	Nearest NSA (miles)	Field Noise Survey?	Modeling Impact Analysis?
GTP	0.00	0	128.20	No	No
Sagwon Compressor Station	75.97	0	60.26	No	No
Galbraith Lake Compressor Station	148.51	0	4.83	No	No
Middle Fork Koyukuk River Horizontal Directional Drill (HDD)	210.99	0	22.34	No	No
Coldfoot Compressor Station	240.11	1	0.92	Yes	Yes
Ray River Compressor Station	332.65	0	16.22	No	No
Yukon River HDD	356.25	4	0.09	Yes	Yes
Minto Compressor Station	421.58	0	15.82	No	No
Tanana River HDD	472.66	246	0.17	Yes	Yes
Healy Compressor Station	517.63	1	0.52	Yes	Yes

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TABLE 9.3.1-1 Identified NSAs Near Project Facilities and Buried Trenchless Locations						
Noise Source	MP	Identified NSAs within 1 Mile	Nearest NSA (miles)	Field Noise Survey?	Modeling Impact Analysis?	
Honolulu Creek Compressor Station	597.58	0	1.20	No	No	
Chulitna River HDD	641.72	0	1.02	Yes	Yes	
Rabideux Creek Compressor Station	675.38	0	1.08	Yes	No	
Deshka River HDD	704.73	0	1.62	No	No	
Theodore River Heater Station	749.26	0	12.30	No	No	
Liquefaction Facility	806.72	371	0.00	Yes	Yes	

As noted in Table 9.3.1-1, site-specific 24-hour baseline noise surveys were conducted near NSAs for several of the planned facilities or buried trenchless locations. The baseline noise level report is provided in Appendix N for the Liquefaction Facility and Appendix O for the Mainline. A summary of the respective results follows.

9.3.1.2 Liquefaction Facility

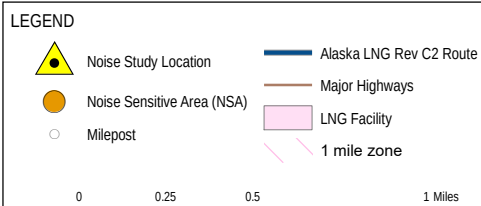
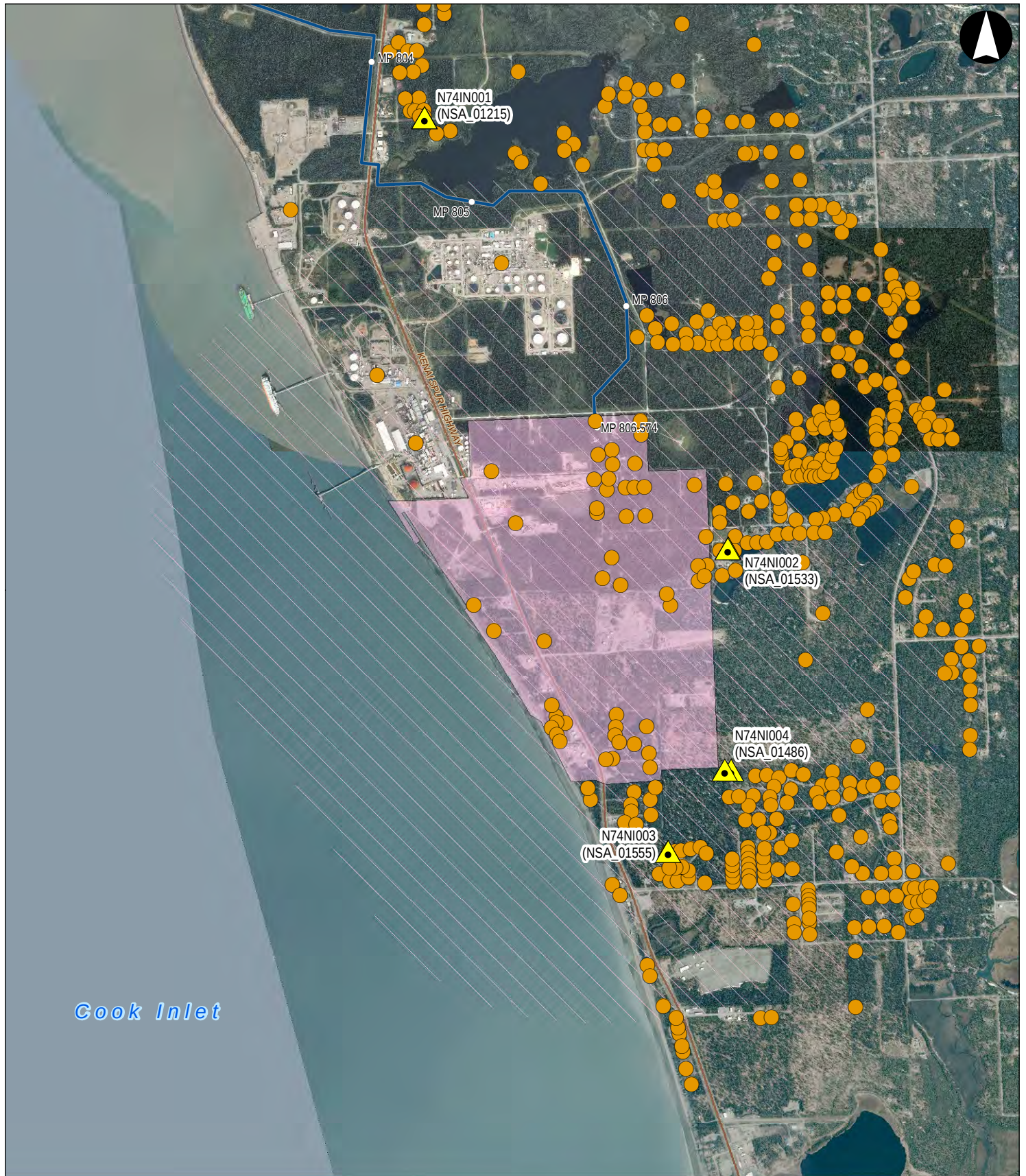
Approximately 440 residential receptors and one recreational campground are located within 1 mile of the Liquefaction Facility. Further analysis was conducted to NSAs closest to the facility. Refer to Appendix N for more information on representative NSA parameters. Baseline outdoor ambient sound level data were collected at selected representative NSAs nearest the proposed Liquefaction Facility during the weeks of March 10, 2015, and June 3, 2015, to represent winter and summer conditions, respectively. Sound level measurements include the 24-hour equivalent sound level (L_{eq}) and day-night sound level (L_{dn}). The L_{eq} is the level of steady sound with the same total (equivalent) energy as the time-varying sound of interest, averaged over a 24-hour period. The L_{dn} is the L_{eq} plus 10 decibels on the A-weighted scale (dBA) added to account for people's greater sensitivity to nighttime sound levels (between the hours of 10 p.m. and 7 a.m.). The A-weighted scale is used because human hearing is less sensitive to low and high frequencies than mid-range frequencies. The human ear's threshold of perception for noise change is considered to be 3 dBA; 6 dBA is clearly noticeable to the human ear, and 10 dBA is perceived as a doubling of noise. Measured day-night average sound level (L_{dn}) values ranged from 43 to 60 A-weighted decibels (dBA). Table 9.3.1-2 and Table 9.3.1-3 show the distances and directions to the NSAs and the measured daytime, nighttime, and L_{dn} values for NSAs near the Liquefaction Facility during winter and summer conditions, respectively. Baseline ambient noise levels are generally higher in the summer. Figure 9.3.1-1 shows the Liquefaction Facility and identified NSA measurement locations. Baseline noise survey details are provided in Appendix N.

TABLE 9.3.1-2 Baseline Ambient Sound Levels – Liquefaction Facility (Winter)					
Noise-Sensitive Area	Distance to NSA (feet)	Direction to NSA	Measured Baseline Ambient $L_{eq(day)}$, dBA	Measured Baseline Ambient $L_{eq(night)}$, dBA	Calculated Baseline Ambient L_{dn} , dBA
NSA 01215	10,500	N	49,55	43,48	51,56
NSA 01533	3,700	E	40,46	36,38	43,47

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TABLE 9.3.1-2 Baseline Ambient Sound Levels – Liquefaction Facility (Winter)					
Noise-Sensitive Area	Distance to NSA (feet)	Direction to NSA	Measured Baseline Ambient $L_{eq(day)}$, dBA	Measured Baseline Ambient $L_{eq(night)}$, dBA	Calculated Baseline Ambient L_{dn} , dBA
NSA 01555	6,600	S	47,56	39,39	48,54
NSA 01486	5,700	SE	36,43	32,32	39,43

TABLE 9.3.1-3 Baseline Ambient Sound Levels – Liquefaction Facility (Summer)					
Noise-Sensitive Area	Distance to NSA (feet)	Direction to NSA	Measured Baseline Ambient $L_{eq(day)}$, dBA	Measured Baseline Ambient $L_{eq(night)}$, dBA	Calculated Baseline Ambient L_{dn} , dBA
NSA 01215	10,500	N	53,54	48,53	55,59
NSA 01533	3,700	E	45,52	44,49	50,56
NSA 01555	6,600	S	48,54	41,54	49,60
NSA 01486	5,700	SE	45,49	42,45	49,52



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LIQUEFACTION FACILITY NOISE ASSESSMENT LOCATIONS

FIGURE 9.3.1-1

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9.3.1.3 Interdependent Project Facilities

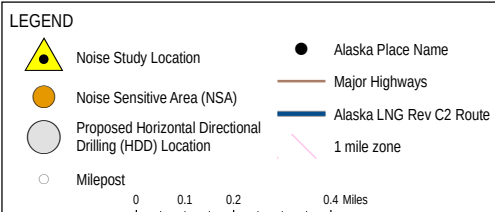
Baseline outdoor ambient sound data were collected at 14 selected NSAs in the vicinity of proposed Project compressor stations, heater stations, and buried trenchless sites along the Mainline route during the weeks of May 22–29, 2015, and August 16–28, 2015. These were the only locations where NSAs were found to be within 1 mile of the facilities, unless noted in the following tables. The two locations with existing L_{dn} values above the FERC threshold of 55 dBA (see Section 9.3.5.1) are in proximity to major roadways. See Appendix O for further details of the Mainline ambient noise survey.

9.3.1.3.1 Pipelines

Table 9.3.1-4 shows the distances, directions, and measured daytime, nighttime, and L_{dn} values for NSAs near planned buried trenchless locations. Figures 9.3.1-2 through 9.3.1-4 show the respective buried trenchless sites and identified NSA measurement locations.

TABLE 9.3.1-4 Baseline Ambient Sound Levels – Buried Trenchless Sites						
Buried Trenchless Site	Noise-Sensitive Area	Distance to NSA (feet)	Direction to NSA	Measured Baseline Ambient $L_{eq(day)}$, dBA	Measured Baseline Ambient $L_{eq(night)}$, dBA	Calculated Baseline Ambient L_{dn} , dBA
Yukon River	NSA_2100	150	W	42,42	29,39	41, 46
Tanana River	NSA_02116	1,600	NW	49,50,50	48,48,49	55
Tanana River	NSA_2101 NSA 02336	3,390	E	54,52	52,53	58, 60
Chulitna River	NSA_2102	5,200	SE	59,59	52,57	61, 64

There are no NSAs within 1 mile of either the PBTL or PTTL.



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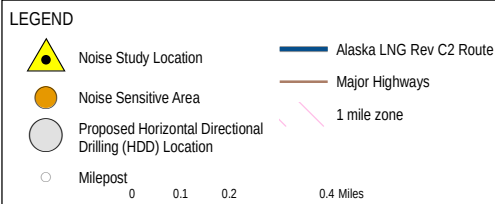
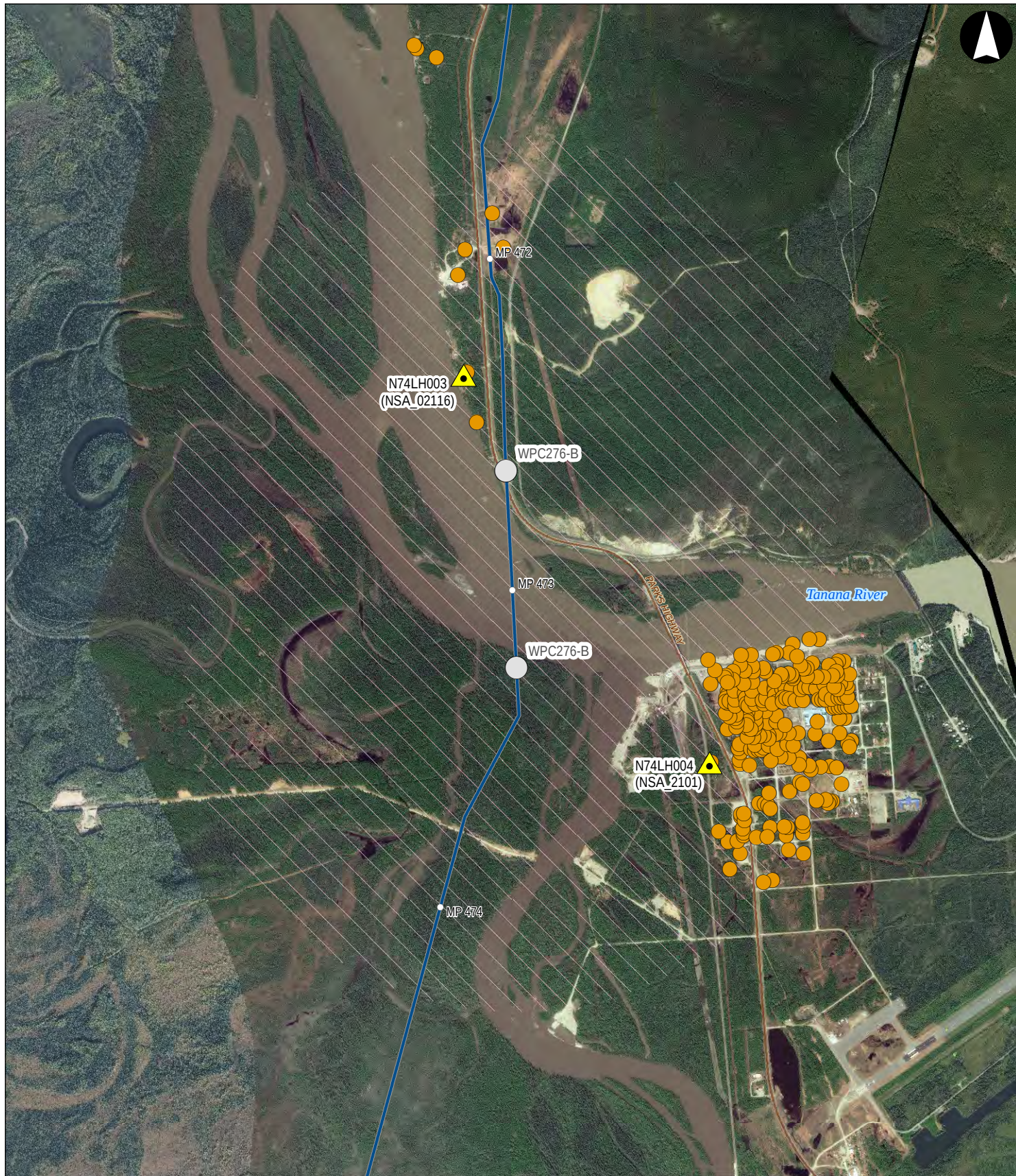
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YUKON RIVER HDD CROSSING NOISE ASSESSMENT LOCATION

FIGURE 9.3.1-2

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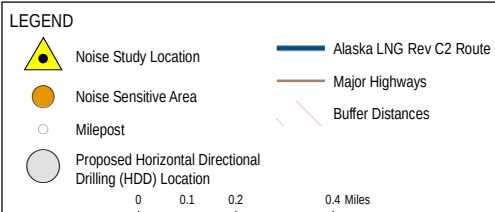
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TANANA RIVER HDD CROSSING NOISE ASSESSMENT LOCATIONS

FIGURE 9.3.1-3

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CHULITNA RIVER HDD CROSSING NOISE ASSESSMENT LOCATIONS

FIGURE 9.3.1-4

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9.3.1.3.2 Pipeline Aboveground Facilities

9.3.1.3.2.1 Compressor Stations

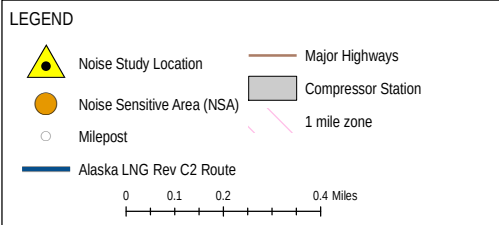
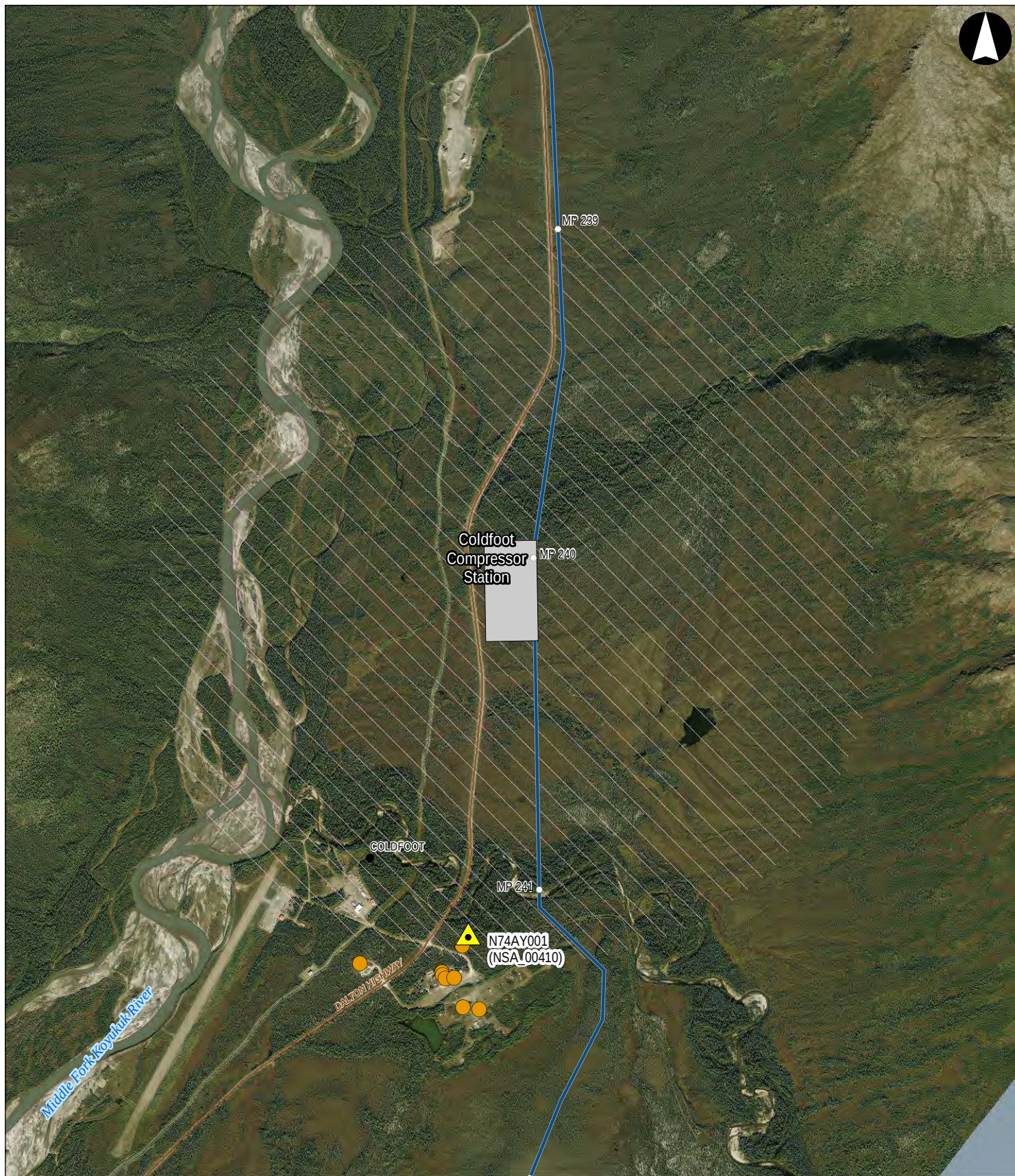
NSAs were only found within 1 mile of the proposed Coldfoot and Rabideux compressor station locations. Table 9.3.1-5 shows the distance, direction and measured daytime, nighttime, and L_{dn} values for NSAs near these two compressor stations. Figures 9.3.1-5 and 9.3.1-6, respectively, show the Coldfoot and Healy compressor stations and identified NSA measurement locations.

TABLE 9.3.1-5 Baseline Ambient Sound Levels – Compressor Stations						
Location	Noise-Sensitive Area	Distance to NSA (feet)	Direction to NSA	Measured Baseline Ambient $L_{eq(day)}$, dBA	Measured Baseline Ambient $L_{eq(night)}$, dBA	Calculated Baseline Ambient L_{dn} , dBA
Coldfoot	NSA_00410	5,770	SSW	42,43	40,41	47,48
Healy	NSA_02337	2,850	NE	48,48	44,46	51,52

Given the general undeveloped, sparsely populated nature of the entire Mainline corridor, the existing ambient noise levels at Coldfoot and Healy are likely comparable to baseline noise levels at other proposed compressor station sites based on land use and proximity to major roadways. The Mainline would follow highways over most of the section where compressor stations would be located. Coldfoot would be located at MP 240.1 near the Dalton Highway with traffic levels typical of the northern compressor stations; Healy would be located at MP 517.6 near the Parks Highway with traffic levels typical of the southern compressor stations.

9.3.1.3.2.2 Heater Stations

As shown in Table 9.3.1-1, there are no NSAs identified within 1 mile of the proposed Theodore River heater station location.



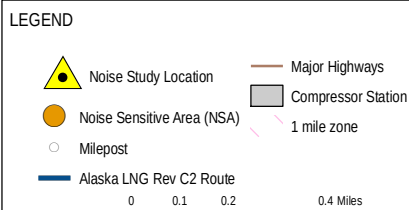
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**COLDFOOT COMPRESSOR STATION
NOISE ASSESSMENT LOCATIONS**

FIGURE 9.3.1-5



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HEALY COMPRESSOR STATION NOISE ASSESSMENT LOCATION

FIGURE 9.3.1-6

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9.3.1.3.2.3 Metering Stations and Mainline Valves

Table 9.3.1-6 provides a summary of the proximity of NSAs to the two Project meter stations and 30 MLBVs along with an analysis of NSA proximity. The baseline noise survey conducted for the Liquefaction Facility discussed in Section 9.3.1.2 included the associate meter station and MLBV 30 given it is located at the facility. Likewise, the baseline surveys conducted for Galbraith Lake, Coldfoot, and Healy compressor stations included the associated MLBVs, located at each station. No baseline surveys were conducted at the remaining MLBVs and GTP meter stations. The GTP meter station and 25 MLBVs do not have NSAs within 0.5 miles. Two MLBVs collocated at compressor stations that have a NSA within 1 mile are included in the baseline survey results discussed in Section 9.3.1.3.2.1. Three MLBVs have NSAs within 0.5 mile.

TABLE 9.3.1-6 Identified NSAs Near Project Meter Stations and MLBV Locations			
Noise Source	MP	Identified NSAs within 0.5 Mile	Nearest NSA (miles)
GTP Mainline Meter Station	0.00	0	131.12
MLBV 2	36.74	0	95.91
MLBV 3 (Sagwon Compressor Station)	75.97	0	60.26
MLBV 4	112.04	0	28.41
MLBV 5 (Galbraith Lake Compressor Station)	148.51	0	4.83
MLBV 6	194.10	0	36.85
MLBV 7 (Coldfoot Compressor Station)	240.11	1	0.92
MLBV 8	286.06	0	21.47
MLBV 9 (Ray River Compressor Station)	332.65	0	16.22
MLBV 10	377.96	0	20.39

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MLBV 11 (Minto Compressor Station)	421.58	0	15.82
MLBV 12	444.90	0	4.25
MLBV 13	467.12	0	0.62
NSA_00410	NSA_00410	NSA_00410	NSA_00410
MLBV 14	492.96	0	4.55
MLBV 15 (Healy Compressor Station)	517.63	1	0.52
MLBV 16	534.79	0	1.44
MLBV 17	538.79	0	1.38
MLBV 18	546.50	0	2.01
MLBV 19	57222.23	0	1.31
MLBV 20 (Honolulu Creek Compressor Station)	597.58	0	1.20
MLBV 21	625.83	0	3.74
MLBV 22	648.16	0	0.86
MLBV 23 (Rabideux Creek Compressor Station)	675.38	0	1.08
MLBV 24	703.67	0	2.29
MLBV 25	725.93	0	1.70
MLBV 26 (Theodore River Heater Station)	749.26	0	12.30
MLBV 27	766.01	2	0.13
MLBV 28	793.34	5	0.17
MLBV 29	799.85	11	0.06
Nikiski Meter Station and MLBV 30	806.72	25	0.03

9.3.1.3.3 GTP

As shown in Table 9.3.1-1, no NSAs have been identified within 1 mile of the GTP. As a result, a baseline survey was not conducted.

9.3.2 Construction Noise Levels and Impacts

Noise level considerations for impacts related to Project construction generally include the following:

- Type of construction equipment used;
- Construction duration;
- Time of day; and
- Distance to NSAs.

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Construction noise levels are analyzed for the some of the sites identified in Table 9.3.1-1. Supporting documentation is provided in appendices P through U.

9.3.2.1 Liquefaction Facility

Construction of the Liquefaction Facility would take place in phases across the facility site. Construction noise impacts were estimated assuming construction activity at different phases for different locations on the site. Typical types and numbers of construction equipment for each phase, along with the maximum sound level at 50 feet for each item, were used to calculate the maximum equipment sound power level. Those sound levels were used to determine predicted composite construction noise levels at the previously identified NSAs around the Liquefaction Facility. Most of the construction equipment operate at the maximum sound level for only a percentage of the entire 24-hour period. This is identified as the utilization time. The duration of equipment operation and the time of day the equipment operates are factors included in the calculation of the estimated Ldn sound levels at the NSAs. Details of the Liquefaction Facility construction noise impact analysis, including a list of construction equipment and sound levels, are provided in Appendix P. The estimated construction sound levels are shown in Table 9.3.2-1.

TABLE 9.3.2-1 Predicted Sound Levels at NSAs from Construction – Liquefaction Facility							
Construction Activity	Noise-Sensitive Area	Distance to NSA (feet)	Direction to NSA	Calculated Baseline Ambient L _{dn} , dBA	Predicted Sound Levels L _{dn} , dBA	Construction L _{dn} + Ambient L _{dn} , dBA	Potential Increase Above Baseline Ambient dBA
Composite	NSA 01215	10,500	N	51	53.5	55.4	1.4
Composite	NSA 01533	3,700	E	43	67.1	67.1	24.1
Composite	NSA 01555	6,600	S	48	63.6	63.7	15.7
Composite	NSA 01486	5,700	SE	39	65.5	65.5	26.5

Blasting plans, if any, for Liquefaction Facility construction are not yet defined and any associated noise impacts.

9.3.2.2 Interdependent Project Facilities

9.3.2.2.1 Pipeline

9.3.2.2.1.1 Mainline

Five river crossings have been identified as possible buried trenchless locations. Three have NSAs within 1 mile, as shown in Table 9.3.1-1. Noise modeling impact assessments were conducted for NSAs at the Yukon, Tanana, and Chulitna rivers. Details of the buried trenchless noise impact analyses are provided in Appendix U.

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Total sound power levels of 115 dBA at entry sites and 103 dBA at exit sites were used to calculate the total sound level at nearby NSAs, assuming simultaneous operation of entry and exit site. The assessment assumes a worst-case condition that all of the equipment would be in non-stop operation through the nighttime hours of 10:00 p.m. to 7:00 a.m. Once trenchless construction has begun it is not practicable to stop until completed, otherwise the likelihood for failure is increased. Predicted sound levels for the buried trenchless sites are shown in Table 9.3.2-2.

TABLE 9.3.2-2 Predicted Sound Levels at NSAs from Construction – Potential Buried Trenchless Locations						
Buried Trenchless Crossing	MP	Noise-Sensitive Areas	Distance to NSA (feet)	Direction to NSA	Calculated Baseline Ambient L_{dn} , dBA	Predicted Sound Levels L_n , dBA
Yukon River	356.25	NSA_2100	716	W	41	47.9
Tanana River	472.66	NSA_02116	1,400	NW	55	35.9
Tanana River	473.26	NSA_2101	3,000	E	58	37.7
		NSA_02336				
Chulitna River	642.43	NSA_2102	4,950	SE	61	31.8
		NSA_02007				

Blasting plans for Mainline construction are not yet defined and any associated noise impacts will be addressed prior to construction.

9.3.2.2.2 Pipeline Aboveground Facilities

9.3.2.2.2.1 Compressor Stations

Noise modeling impact assessments methodology and results are provided in appendices Q and R for the Coldfoot, and Healy compressor stations, respectively. With a 24-hour construction schedule, the maximum predicted level at the closest NSAs is less than 55 dBA L_{dn} for the Coldfoot station and greater than 55 dBA L_{dn} for and Healy compressor station. The estimated construction sound levels are shown in Table 9.3.2-3

TABLE 9.3.2-3 Predicted Sound Levels at NSAs from Construction – Compressor Stations							
Compressor Station	Noise-Sensitive Area	Distance to NSA (feet)	Direction to NSA	Calculated Baseline Ambient L_{dn} , dBA	Predicted Sound Levels L_{dn} , dBA	Construction L_{dn} + Ambient L_{dn} , dBA	Potential Increase Above Baseline Ambient dBA
Coldfoot	NSA_00410	5,770	SSW	47	50.3	52.0	5.0
Healy	NSA_02337	2,850	NE	52	61.5	62.0	11.0

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9.3.2.2.2 Heater Station

As shown in Table 9.3.1-1, there are no NSAs identified within 1 mile of the proposed Theodore River heater station location.

9.3.2.2.3 Metering Stations and Mainline Block Valves (MLBVs)

Construction noise impact analyses for metering stations and mainline valve sites collocated at the Liquefaction Facility and compressor stations were included in the analysis discussed in Sections 9.3.1.3.2.1 and 9.3.2.2.2.1 respectively.

9.3.2.2.3 Pipeline Associated Infrastructure

Noise impact analyses for pipeline associated infrastructure (such as granular material mine-site operations) have not yet been conducted. These will be provided prior to construction.

9.3.2.2.4 GTP

As shown in Table 9.3.1-1, no NSAs have been identified within 1 mile of the GTP, therefore, a noise modeling analysis has not been conducted.

9.3.2.3 Non-jurisdictional Facilities

The PBU MGS project is within proximity to the GTP and is not within 1 mile of any NSAs. The PTU Expansion project is within the existing developed PTU areas that are not within 1 mile of any NSAs.

Kenai Spur Highway relocation project construction would occur within 1 mile of several NSAs. Potential impacts and mitigation will be evaluated after completion of the selection of the preferred route and available design and construction information.

9.3.3 Regulatory Requirements for Noise – Construction

For construction, the applicable noise limit is 55 dBA L_n , which means that between the hours of 10:00 p.m. and 7:00 a.m. local time, the equivalent sound level (L_{eqt}) must not exceed 55 dBA. See 18 C.F.R. 157.206(b)(5)(iii). There are no other identified numeric regulatory requirements specific to project construction noise for any of the Project components.

9.3.4 Operations Noise Levels and Impacts

9.3.4.1 Liquefaction Facility

Details of the Liquefaction Facility noise impact and mitigation analysis are provided in Appendix P. Major noise producing equipment includes turbine compressors, process compressors, connected piping, fans, motors, and pumps. Other sound sources include power generation, heat recovery steam generators, and steam turbine and utility equipment such as air compressors and air dryers.

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A computer noise model of the proposed Liquefaction Facility was created using SoundPLAN version 7.4, as distributed by Braunstein + Berndt GmbH. Sound levels at NSAs were calculated based on octave band sound power emission levels of equipment, taking into account terrain effects using a topological digital ground model created from the Project Geographic Information System (GIS) library. Predicted sound levels for the Liquefaction Facility at nearby NSAs are shown in Table 9.3.4-1.

TABLE 9.3.4-1 Predicted Sound Levels at NSAs from Normal Operations – Liquefaction Facility						
Noise-Sensitive Area	Distance to NSA (feet)	Direction to NSA	Calculated Baseline Ambient L _{dn} , dBA ^a	Predicted Sound Level L _{dn} , dBA	Total Predicted L _{dn} , dBA	Potential Increase Above Baseline Ambient
NSA 01215	10,500	NW	51	39.0	51.3	0.3
NSA 01533	3,700	E	43	54.8	55.1	12.1
NSA 01555	6,600	S	48	47.6	50.8	2.8
NSA 01486	5,700	SE	39	53.5	53.7	14.7
^a This column includes the lower of the 24-hour noise samples measured in the baseline survey to characterize the worst-case potential increase above ambient.						

9.3.4.1.1.1 Marine Vessels

LNGC routes traversing Cook Inlet have not yet been finalized. However, it is anticipated that they would be located more than a mile from shore. Thus, any onshore NSAs along the Cook Inlet shipping routes would not be adversely affected by LNGC noise.

9.3.4.2 Interdependent Project Facilities

9.3.4.2.1 Pipeline

9.3.4.2.1.1 Compressor Stations

Compressor station noise impact analyses are provided in appendices Q, and R, for Coldfoot, , and Healy compressor stations, respectively. Predicted sound levels are shown in Table 9.3.4-2.

TABLE 9.3.4-2 Predicted Sound Levels at NSAs from Normal Operations – Compressor Stations							
Station	Noise-Sensitive Area	Distance to NSA (feet)	Direction to NSA	Calculated Baseline Ambient L _{dn} , dBA ^a	Predicted Sound Level L _{dn} , dBA	Total Predicted L _{dn} , dBA	Potential Increase Above Baseline Ambient
Coldfoot	NSA_00410	5,770	SSW	47	40.7	47.9	0.9
Healy	NSA_02337	2,850	NE	52	53.0	55.5	3.5
^a This column includes the lower of the 24-hour noise samples measured in the baseline survey to characterize the worst-case potential increase above ambient.							

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Compressor stations occasionally require a “blowdown” event, wherein an upset would require high pressure gas to be rapidly vented to decrease line pressure. Typically, sound levels would start high and rapidly decrease as the line depressurizes. Silencers are proposed for blowdown stacks to limit the maximum sound levels. Thus, the modeled maximum initial sound level at the nearest NSAs for Coldfoot, and Healy are 45 and -48 dBA respectively. See Appendices Q and R. Potential vibrations effects on NSAs related to compressor station operations sound levels are not anticipated but will be further evaluated prior to the draft EIS.

9.3.4.2.1.2 Heater Stations

As shown in Table 9.3.1-1, there are no NSAs identified within 1 mile of the proposed Theodore River heater station location.

9.3.4.2.1.3 Metering Stations and MLBVs

The Liquefaction Facility meter station noise impacts were considered as part of the overall facility noise assessment discussed in Section 9.3.4.1 and Appendix P. The following is the noise impact assessment of the sound level for MLBV normal operational (i.e., planned) blowdown at the currently identified NSAs and the mitigation that would be required to meet a Day-Night Level (L_{dn}) of 55 dBA or less at the identified NSAs. The assessment was based on sound power level for an unmitigated blowdown in Table 9.3.5-3. The normal operating scenario is that the blowdown will be conducted during the daytime hours of 07:00 to 22:00 and the maximum duration of the blowdown will be three hours. This scenario allows comparison of the L_{dn} of 55 at the NSA if the measured or predicted sound level is 64 or less at the NSA during a blowdown operation.

TABLE 9.3.4-3 Sound Power for an Un-Mitigated Blowdown Vent Operation										
	Octave Band Center Frequency - Hz									Awt
	31.5	63	125	250	500	1000	2000	4000	8000	
Sound Power Level – L_w in dB	155	158	160	167	170	168	165	159	153	172

A large majority of the MLBVs have existing NSAs that are a distance greater than 1 mile from MLBV location. In that case a vent muffler with a minimal sound level reduction would be sufficient to limit the sound level of the vent operation to 64 dBA or less at any NSA at a distance of 1 mile or greater. The performance of this vent muffler is given in Table 9.3.4-4.

TABLE 9.3.4-4 Vent Silencer Dynamic Insertion Loss (DIL) in dB – Minimal Design										
	Octave Band Center Frequency - Hz									
	31.5	63	125	250	500	1000	2000	4000	8000	
DIL – L_w in dB	0	0	6	25	35	35	30	20	10	

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The minimal design muffler alone would be insufficient to limit onsite personnel noise exposure to permissible safety limits because the estimated sound level with this silencer at a distance of 100 feet would be approximately 109 dBA. Therefore, additional in-plant personnel noise mitigation would be required (e.g., local barriers).

There are three MLBVs listed in Table 9.3.4-5 that have NSAs within a 0.5-mile radius of the valve location that would be potentially impacted by normal blowdown operating noise.

TABLE 9.3.4-5 MLBV Locations with Nearby NSAs					
Facility Name	Facility Type	Milepost	NSAs within 0.5 mile	Distance to Nearest NSA (mi)	Nearest NSA ID
MLBV 27	MLBV Pad	766.01	2	0.13	NSA_01769
MLBV 28	MLBV Pad	793.34	5	0.17	NSA_01078
MLBV 29	MLBV Pad	799.85	11	0.06	NSA_00846

One noise mitigation option is to increase the performance of the vent silencer. Table 9.3.4-6 provides the sound attenuation performance for a premium silencer, which represents the maximum performance that can be achieved for this type of operation.

TABLE 9.3.4-6 Vent Silencer Dynamic Insertion Loss (DIL) in dB-Premium Design									
	Octave Band Center Frequency - Hz								
	31.5	63	125	250	500	1000	2000	4000	8000
DIL – L_w in dB	5	20	35	45	55	55	45	35	25

With a premium muffler, the estimated sound level would be equal to or less than 64 dBA at all of the MLBV installations of Table 9.3.5-5 with the exception of MLBV 27 and MLBV 28. At these two locations additional mitigation would be required, which can include noise barriers near the NSAs or relocation of the MLBV.

Operational noise impact for MLBV blowdown vents can be mitigated with a vent muffler to attenuate the sound levels to an Ldn of 55 dBA or less where the distance between the vent and the NSA is greater than 0.17 mile. Where an NSA is located less than 0.17 mile, additional mitigation including local sound barrier(s) to limit the Ldn to 55 dBA or less.

9.3.4.2.2 GTP

As shown in Table 9.3.1-1, no NSAs have been identified within 1 mile of the GTP. Therefore, a noise modeling analysis has not been conducted at the facility. Mitigation measures that address opportunities

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to minimize noise from the facility during operations would be incorporated into the Project design. Typical mitigation measures would be based on noise control equipment, enclosure design, and noise absorption capabilities.

9.3.4.3 Non-jurisdictional Facilities

The PBU MGS project is in proximity to the GTP and are not within 1 mile of any NSAs. The PTU Expansion project is within the existing developed PTU areas that are not within 1 mile of any NSAs.

Potential impacts and mitigation from the Kenai Spur Highway relocation project will be evaluated after the selection of the preferred route based on proximity to NSAs, and available design information.

9.3.5 Regulatory Requirements for Noise – Operations

9.3.5.1 Federal

At any location, both the magnitude and frequency of environmental noise may vary considerably over the course of the day and throughout the week. This variation is caused in part by changing weather conditions, but also by the effects of seasonal groundcover and other activity. Two measures used by federal agencies to relate the time-varying quality of environmental noise to its known effect on people are the 24-hour equivalent sound level ($L_{eq}(24)$) and the L_{dn} . The $L_{eq}(24)$ is the level of steady sound with the same total (equivalent) energy as the time-varying sound of interest, averaged over a 24-hour period. The L_{dn} is the $L_{eq}(24)$ with 10 decibels added to the nighttime sound levels between the hours of 10:00 pm and 7:00 am to account for people's greater sensitivity to sound during nighttime hours.

In 1974, EPA published "Information on Levels of Environmental Noise Requisite to Protect Public Health and Welfare with an Adequate Margin of Safety." This publication evaluated the effects of environmental noise with respect to human health and safety. EPA identified an L_{dn} of 55 dBA as a threshold for outdoor noise in residential areas (EPA, 1974). This noise level is often used by federal and state agencies to establish noise limitations for cumulative noise exposure. With a 10 decibel nighttime weighting penalty, a 55 dBA L_{dn} noise level equates to a 24-hour continuous noise level of 48.6 dBA $L_{eq}(24)$. FERC limits the noise attributable to stationary energy facilities (such as compressor stations) to 55 dBA L_{dn} at noise-sensitive areas such as schools, hospitals, or residences.

The NPS and USFWS manage lands near the Project and may have an interest in potential noise impacts (Figure 9.3.5-1). A discussion and mapping of federal lands in the vicinity of the Project are provided in Resource Report No. 8. The NPS does not have a numeric noise criterion for human exposure applicable to the Project. However, the NPS has a Soundscape Management Policy that states, "Using appropriate management planning, superintendents will identify what levels and types of unnatural sound constitute acceptable impacts on park natural soundscape. In and adjacent to parks, the NPS will monitor human activities that generate noise that adversely affects park soundscapes, including noise caused by mechanical or electronic devices" (NPS, 2006). As shown in Figure 9.3.5-2, the DNPP and Gates of the Arctic National Park and Preserve, both managed by the NPS, are adjacent to the Mainline corridor.

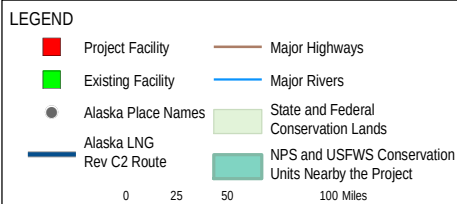
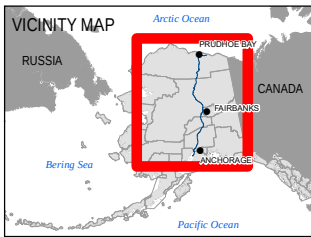
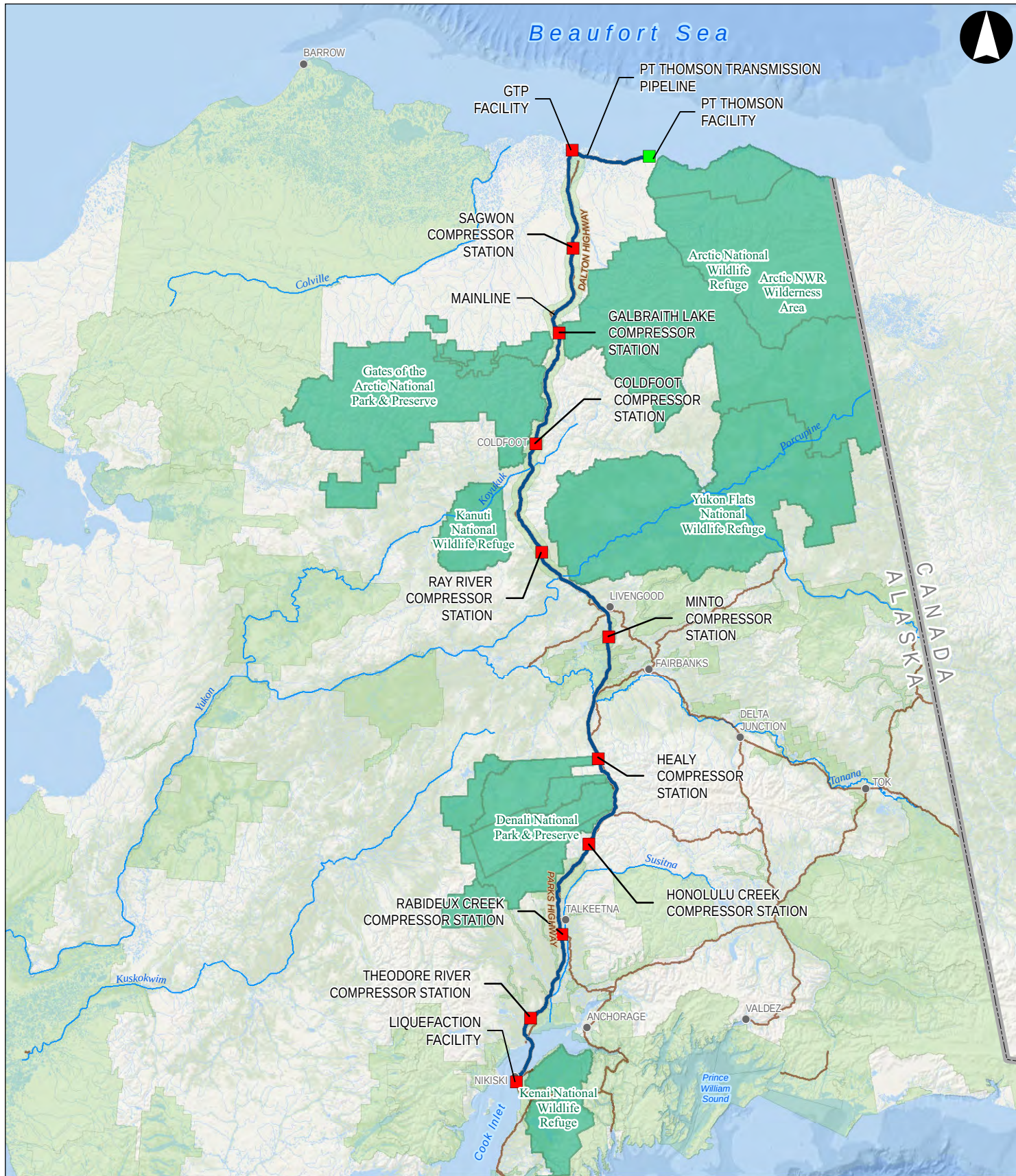
The USFWS does not have a numeric noise criterion for human exposure applicable to the Project. The USFWS does preserve "natural soundscapes" as an "aspect of wilderness character" to "prevent or

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minimize...unnatural sounds that adversely affect wilderness resources or values or visitors' enjoyment of them" (USFWS, 2008). Four NWRs managed by the USFWS are near the Mainline corridor: ANWR, Yukon Flats NWR, Kanuti NWR, and Kenai NWR.

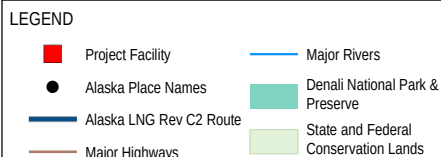
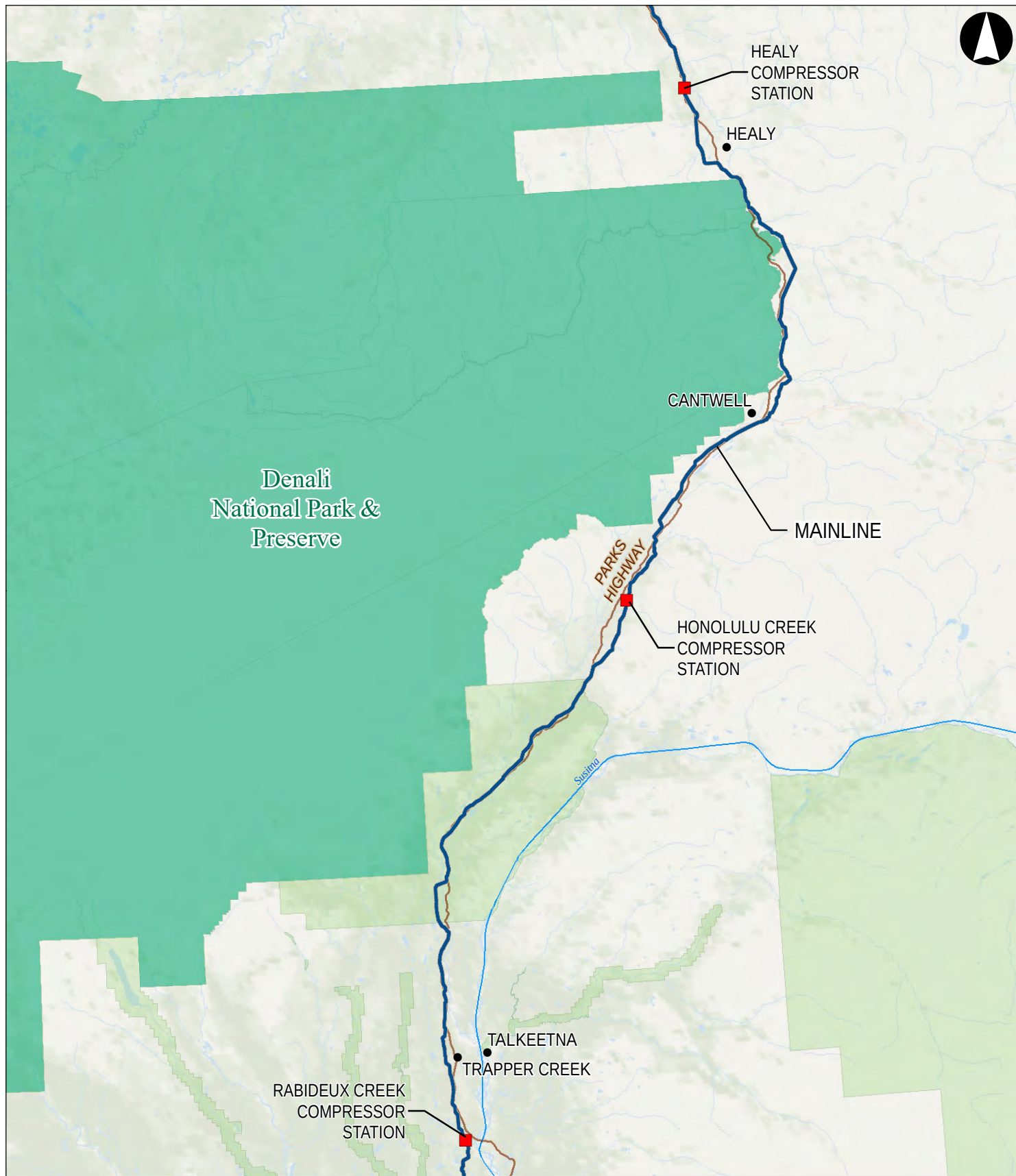
9.3.5.2 State

The State of Alaska has not adopted noise regulations applicable to the Project. In the absence of an applicable state noise level limit, the FERC noise criterion of 55 dBA L_{dn} would be used to ensure the Project's compliance with noise regulatory requirements.



PROJECT VICINITY TO NEARBY NPS AND USFWS CONSERVATION UNITS

FIGURE 9.3.5-1



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PROJECT AREA IN PROXIMITY TO DENALI NATIONAL PARK AND PRESERVE

FIGURE 9.3.5-2

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9.3.5.3 Local

Except for the Matanuska-Susitna Borough (MSB), none of the local jurisdictions have adopted noise regulations applicable to the Project.

The MSB has a noise standard that limits noise for Core Area Conditional Use Permits according to the applicable zoning district classification (e.g., residential, commercial, industrial) of the noise source and the NSAs (MSB, 2013). A portion of the Mainline corridor is located in the MSB area and would be considered an industrial entity, but it is more than 20 miles from the designated Core Area. Regardless, the FERC criterion of 55 dBA L_{dn} is equivalent to a 24-hour continuous noise level of 48.6 dBA L_{eq} (24), which is less than the 60 dBA daytime and 50 dBA nighttime limits of the MSB. Thus, the more-stringent FERC noise criterion of 55 dBA L_{dn} will be applicable to the Project.

9.3.6 Regulatory Compliance and Mitigation Measures – Construction

Noise mitigation plans are not yet available for any of the Project components. The template for a Project *Construction Noise Abatement Plan* is attached as Appendix V.

9.3.6.1 Liquefaction Facility

As noted in Section 9.3.3, the generally applicable noise limit is 55 dBA L_n because there are no other specific component noise requirements for construction of the Liquefaction Facility. Predicted noise levels are as high as 67 dBA at nearby NSAs. Noise mitigation measures will be included in Appendix T that will be completed prior to the issuance of the DEIS and a vegetative buffer would be left in place along the eastern and southern boundaries of the site, which was not included in the modeling. The presence of the buffer would reduce noise levels during construction and operations.

9.3.6.2 Interdependent Project Facilities

9.3.6.2.1 Pipeline

Predicted noise levels at the two buried trenchless sites modeled would be within the applicable regulatory requirement of 55 dBA L_n at nearby NSAs. Noise modeling of construction of Coldfoot compressor stations predicts that noise levels at the nearest NSAs would be less than 55 dBA L_{dn} . Modeling of the Healy Compressor Station resulted in a prediction of maximum noise levels at nearby NSAs 61.5 dBA L_{dn} . Noise mitigation measures for compressor and heater station construction will be described in Appendix T that will be completed prior to the issuance of the DEIS.

9.3.6.2.2 GTP

The GTP would be constructed in a heavily industrialized area. Because adjacent land uses are compatible, noise from construction of the GTP is of low concern.

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9.3.7 Regulatory Compliance and Mitigation Measures - Operations

9.3.7.1 Liquefaction Facility

All significant noise sources at the Liquefaction Facility would have noise mitigation measures applied to them, as detailed in Appendix P. The mitigation measures include noise specifications, acoustical duct or pipe lagging, combustion turbine exhaust silencers, acoustical enclosures, inline piping silencers, and enclosing noisy skids inside buildings. With the identified mitigation measures applied, predicted noise levels for the Liquefaction Facility demonstrate compliance with the 55 dBA L_{dn} regulatory limit at nearby NSAs.

9.3.7.2 Interdependent Project Facilities

9.3.7.2.1 Pipeline Aboveground Facilities

All significant noise sources at compressor and heater stations would have noise mitigation applied to them as indicated in the sound level assessments results provided in appendices Q through T. The mitigation measures include noise specifications, acoustical duct or pipe lagging, combustion turbine exhaust silencers, acoustical enclosures, inline piping silencers, blowdown silencers, and enclosing noisy skids inside buildings. With the identified mitigation measures applied, predicted noise levels for the modeled compressor and heater stations demonstrate compliance with the 55 dBA L_{dn} regulatory limit at nearby NSAs.

9.3.7.2.2 GTP

The GTP would be located in a heavily industrialized area, therefore, would be a compatible land use. Mitigation measures that address opportunities to minimize noise from the facility during operations would be incorporated into the Project design.

9.4 REFERENCES

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APPENDIX H PROJECT NSPS, NESHAPS, and RMP APPLICABILITY ANALYSIS

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1.0 NEW SOURCE PERFORMANCE STANDARDS (NSPS)

Pursuant to Section 111 of the CAA, EPA promulgates NSPS, codified in 40 C.F.R. Part 60, for certain newly constructed, modified, or reconstructed sources of emissions of criteria pollutants. These standards are based on best demonstrated technology for air pollution control of specified equipment and may be expressed as numerical emission limits, performance standards, or work practices. Subpart A of Part 60 establishes general provisions for sources subject to the various NSPS subparts, including general performance testing, monitoring, notification, reporting, and recordkeeping requirements.

A preliminary analysis of NSPS that may apply to the proposed Project facilities is provided below. Final applicability determinations would be made based on final facility design. Table 1 provides a summary of the NSPS categories under 40 C.F.R. 60 that are potentially applicable to emission units included in the Project.

TABLE 1 Preliminary NSPS Applicability Summary			
NSPS Subpart	Applicability		
	Liquefaction Facility	Compressor and Heater Stations	GTP
Subpart A – General Provisions	Yes	Yes	Yes
Subpart Da – Electric Utility Steam Generation Units	No	No	No
Subpart Db – Industrial, Commercial, and Institutional Steam Generating Units	No	No	Yes
Subpart Dc – Small Industrial, Commercial, and Institutional Steam Generating Units	No	Yes	No
Subpart Kb – Volatile Organic Liquid Storage Vessels	TBD	No	TBD
Subpart CCCC – Commercial and Industrial Solid Waste Incineration Units	No	Yes	No
Subpart IIII – Stationary Compression Ignition Internal Combustion Engines	Yes	No	Yes
Subpart JJJJ – Stationary Spark Ignition Internal Combustion Engines	No	Yes	No
Subpart KKKK – Stationary Combustion Turbines	Yes	Yes	Yes
Subpart OOOOa – Standards for Performance for Crude Oil and Natural Gas Facilities	Yes	Yes	Yes

1.1 LIQUEFACTION FACILITY

The Liquefaction Facility would be subject to the flare design and operating requirements of Subpart A for any flares that serve as a control device to comply with the applicable requirements of other NSPS-regulated units. Subpart A restricts visible emissions from flares and requires the documentation of design data to ensure proper flare operation. Final applicability determinations for the flares would be made based on final facility design.

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NSPS Subpart Da, Standards of Performance for Electric Utility Steam Generating Units, applies to electric utility steam generating units with a heat input capacity greater than 250 MMBtu/hr and for which construction, reconstruction, or modification commenced after September 18, 1978. The Liquefaction Facility would not include any steam generating units constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW net electrical output to any utility power distribution for sale and, as such, would not be subject to the requirements of Subpart Da.

NSPS Subparts Db and Dc regulate emissions from industrial, commercial, and institutional steam generating units, and may apply to the emission units at the facility if gas-fired steam generating units (or units that heat other liquids such as oil or glycol for process operations) are included in the facility design.

NSPS Subpart Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units, applies to stationary source steam generating units with a heat input capacity greater than 100 MMBtu/hr and for which construction, reconstruction, or modification commenced after June 19, 1984. A steam generating unit is defined in Subpart Db as a device that combusts any fuel or byproduct/waste and produces steam or heats water or heats any heat transfer medium. Subpart Db does not apply to process heaters, which are devices primarily used to heat a material to initiate or promote a chemical reaction in which the material participates as a reactant or catalyst. The current facility design plan does not include any steam generating units with a heat input capacity greater than 100 MMBtu/hr and, as such, would not be subject to the requirements of Subpart Db. NSPS Subpart Dc, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units, applies to stationary steam generating units, as defined in 40 C.F.R. 60.41c, with a heat input capacity less than 100 MMBtu/hr and greater than 10 MMBtu/hr and for which construction, reconstruction, or modification commenced after June 9, 1989. The current facility design plan does not include any steam generating units with a heat input capacity greater than 10 MMBtu/hr and less than 100 MMBtu/hr, each.

NSPS Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels for which Construction, Reconstruction, or Modification Commenced After July 23, 1984, applies to owners and operators of storage vessels constructed, reconstructed, or modified after July 23, 1984 with a capacity greater than or equal to 75 cubic meters (m³) (19,813 U.S. gallons) and used to store a volatile organic liquid, which is any organic liquid that can emit VOCs, as defined in 40 C.F.R. 51.100, into the atmosphere. Subpart Kb does not apply to storage vessels with a capacity greater than or equal to 75 m³ (19,813 U.S. gallons) but less than 151 m³ (39,890 U.S. gallons) and used to store a liquid with a maximum true vapor pressure less than 15.0 kilopascals (kPa) (2.2 pounds per square inch [absolute] (psia)). Subpart Kb also does not apply to storage vessels with a capacity greater than or equal to 151 m³ (39,890 U.S. gallons) used to store a volatile organic liquid with a maximum true vapor pressure less than 3.5 kPa (0.51 psia). Additionally, the following storage vessels are exempt from Subpart Kb per 40 C.F.R. 60.110b(d):

- Pressure vessels designed to operate in excess of 204.9 kPa and without emissions to the atmosphere;
- Storage vessels permanently attached to mobile vehicles such as trucks, railcars, barges, or ships; and
- Storage vessels with a design capacity less than or equal to 1,589.874 m³ (420,000 U.S. gallons) used for petroleum or condensate stored, processed or treated prior to custody transfer. Custody transfer is defined in 40 C.F.R. 60.111b as the transfer of produced petroleum and/or condensate,

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after processing and/or treatment in the producing operations, from storage vessels or automatic transfer facilities to pipelines or any other forms of transportation.

The Liquefaction Facility is anticipated to include various storage tanks including:

- LNG storage tanks;
- Hydrocarbon condensate storage tanks;
- Diesel fuel oil tanks;
- Propane refrigerant tanks; and
- Ethane storage tanks.

The current facility design plan includes two LNG storage tanks with a capacity of approximately 240,000 m³ (63,000,000 U.S. gallons), each, but because the true vapor pressure of the VOC components of LNG when maintained at storage temperature (-260 °F) would be less than 3.5 kPa, the LNG storage tanks would be exempt from Subpart Kb.

Approximately 175 m³ (46,230 gallons) per day of condensate would be removed from the natural gas stream by the liquefaction process and stored in a condensation storage tank. This tank would be used to store condensate processed or treated prior to custody transfer, as defined in 40 C.F.R. 60.111b, and as such, would be exempt from Subpart Kb if the capacity of the condensate storage tank is less than 1,589.875 m³ (420,000 gallons).

Diesel fuel storage tanks at the Liquefaction facility would range in size from 200 to 280 m³ (55,000 to 75,000 gallons), each, but because the maximum true vapor pressure of diesel is much less than 3.5 kPa, the diesel storage tanks would be exempt from Subpart Kb.

The propane and ethane storage tanks planned for the Liquefaction Facility would be pressure vessels designed to operate in excess of 204.9 kPa and without emissions to the atmosphere. As a result, these storage vessels would be exempt from Subpart Kb.

The capacities of other storage tanks and the expected composition of the volatile organic liquid contents that would be stored at the Liquefaction Facility have not yet been determined. Final applicability determinations would be made for all storage tanks at the Liquefaction Facility based on the final facility design.

NSPS Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, applies to owners and operators of stationary compression ignition internal combustion engines (CI ICE) that commence construction after July 11, 2005 where the stationary CI ICE are either manufactured after April 1, 2006 and are not fire pump engines or manufactured as a certified National Fire Protection Association (NFPA) fire pump engine after July 1, 2006. Subpart IIII emission standards for stationary CI ICE are based on the engine rating, cylinder displacement, model year, and whether or not the CI ICE is an emergency engine, as defined under 40 C.F.R. 60.4211(f). All stationary CI ICE installed and

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operated at the Liquefaction Facility that are subject to Subpart IIII would be required to burn ultra-low sulfur diesel (ULSD).

The preliminary design plan for the Liquefaction Facility includes the following potentially affected engines:

- One non-emergency engine air compressor drive rated for a maximum power output of approximately 300 horsepower, and
- One firewater pump engine rated for a maximum power output of approximately 575 horsepower (429 kW), each.

Each of these units must be designed to meet the applicable Subpart IIII emission limits. Under 40 C.F.R. 60.4209(a), the fire pump CI ICE would require the installation of a non-resettable hour meter prior to startup if the engine does not meet the emission standards in Subpart IIII that are applicable to non-emergency engines. Additionally, the fire pump CI ICE would be required to be in compliance with the non-vacated portions of the operating and maintenance procedures specified in 40 C.F.R. 60.4211(f).

NSPS Subpart JJJJ, Standards of Performance for Stationary Spark Injection Internal Combustion Engines, applies to stationary spark ignition internal combustion engines (SI ICE) for which construction, modification, or reconstruction commenced after June 12, 2006. Currently, the Project plan does not include SI ICE at the Liquefaction Facility. If any stationary SI ICE are installed at the Liquefaction Facility and subject to Subpart JJJJ, then the stationary SI ICE would be required to meet the NO_x, CO, and VOC emission limits in Table 1 of Subpart JJJJ per 40 C.F.R. 60.4233(e).

NSPS Subpart KKKK, Standards of Performance for Stationary Combustion Turbines, applies to stationary combustion turbines, including any associated duct burners, with a heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBtu) per hour and for which construction, modification, or reconstruction commenced after February 18, 2005. As a result, Subpart KKKK applies to all of the combustion turbines proposed for the Liquefaction Facility. The preliminary Project plan includes six gas-fired simple cycle combustion turbines for compressor mechanical drives and four gas-fired combined cycle turbines for power generation at the Liquefaction Facility. The associated emissions from a combined turbine and heat recovery steam generator are subject to the Subpart KKKK NO_x and SO₂ emission requirements. Each new gas-fired turbine is expected to be equipped with DLN/DLE emission controls and would be capable of achieving the applicable Subpart KKKK NO_x emission limits. Additionally, the new combustion turbines at the Liquefaction Facility would burn fuel gas with a sulfur content no greater than 3 ppmv S, resulting in SO₂ emissions well below the SO₂ limits in Subpart KKKK.

- NSPS Subpart OOOOa, Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification, or Reconstruction Commenced after September 18, 2015, establishes emission standards and compliance schedules for the control of SO₂, VOC, and greenhouse gases (GHG) in the form of a limitation on emissions of methane from affected facilities in the crude oil and natural gas source category. Subpart OOOOa would apply to certain components of the Liquefaction Facility that include:
- Each centrifugal compressor using wet seals;

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- Each single continuous bleed natural gas-driven pneumatic controller;
- Storage vessels, as defined in 40 C.F.R. 60.4530a, with potential VOC emissions equal to or greater than 6 tons per year;
- Each pneumatic pump that is a natural gas-driven diaphragm pump; and
- The group of all equipment, except compressors, within a process unit. The definition of a process unit in 40 C.F.R. 60.5430a includes components assembled for the fractionation of liquids into natural gas products, or other operations associated with the processing of natural gas products.

Owners and operators of centrifugal compressors using wet seals subject to Subpart OOOOa must reduce methane and VOC emissions from each centrifugal compressor wet seal fluid degassing system by 95.0 percent. If a control device, such as a flare or thermal oxidizer, is used to reduce emissions, then the wet seal fluid degassing system must be equipped with a cover and closed vent system that meet the operating and design requirements in Subpart OOOOa and must be routed to a control device meeting the specifications in Subpart OOOOa. The closed vent system can be routed to a process as an alternative to routing the closed vent system to a control device.

Under Subpart OOOOa, each continuous bleed natural gas-driven pneumatic controller at a natural gas processing plant must have a bleed rate of zero. Subpart OOOOa requires that such pneumatic controllers at a natural gas processing plant be tagged with the month and year of installation, reconstruction, or modification and identification information that allows traceability to the records for that pneumatic controller.

Under Subpart OOOOa, each pneumatic pump that is a natural gas-driven diaphragm pump operating at the Liquefaction Facility must have a natural gas emission rate equal to zero.

Certain monitoring, recordkeeping and reporting requirements and VOC emission standards are applicable to storage vessels subject to Subpart OOOOa. Exceptions to Subpart OOOOa applicability exist for storage vessels subject to and controlled in accordance with the requirements for storage vessels in Subpart Kb or 40 C.F.R. Part 63 Subparts G, CC, HH, or WW. The following vessels are not storage vessels subject to regulation under Subpart OOOOa:

- Storage vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges or ships), and are intended to be located at a site for less than 180 consecutive days.
- Process vessels such as surge control vessels, bottoms receivers or knockout vessels; and
- Pressure vessels designed to operate in excess of 204.9 kPa and without emissions to the atmosphere.

The Liquefaction Facility processing equipment, except compressors, subject to Subpart OOOOa must meet the equipment leak GHG and VOC standards in 40 C.F.R. 60.5400, which cross-reference equipment leak standards in Subpart VVa, Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic

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Subpart OOOOa notification, reporting, and recordkeeping requirements are outlined in 40 C.F.R. 60.5420. In addition, 40 C.F.R. 60.5421a and 40 C.F.R. 60.5422a contain recordkeeping requirements and reporting requirements, respectively, for equipment at onshore natural gas processing plants subject to the equipment leak standards in Subpart OOOOa, which include semiannual reporting requirements.

1.2 INTERDEPENDENT PROJECT FACILITIES

1.2.2 Compressor and Heater Stations

NSPS Subpart Da, Standards of Performance for Electric Utility Steam Generating Units, applies to electric utility steam generating units with a heat input capacity greater than 250 MMBtu/hr and for which construction, reconstruction, or modification commenced after September 18, 1978. The compressor stations and heater stations would not include any steam generating units constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW net electrical output to any utility power distribution for sale. As a result, the compressor stations and heater stations would not include any equipment subject to the requirements of Subpart Da. NSPS Subpart Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units, applies to stationary source boilers with a heat input capacity greater than 100 MMBtu/hr and for which construction, reconstruction, or modification commenced after June 19, 1984. At this time, the compressor stations and heater stations would not include any steam generating units with a heat input capacity greater than 100 MMBtu/hr and, as such, would not be subject to the requirements of Subpart Db.

NSPS Subpart Dc, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units, applies to stationary source boilers with a heat input capacity less than 100 MMBtu/hr and greater than 10 MMBtu/hr and for which construction, reconstruction, or modification commenced after June 9, 1989. All of the compressor stations are planned to include a number of natural gas-fired auxiliary glycol heaters rated for a maximum heat input capacity of approximately 3 MMBtu/hr, each. Because each of these units would have a maximum heat input capacity less than 10 MMBtu/hr, these units would not be subject to the requirements of Subpart Dc.

One compressor station and the heater stations are planned to include a set of five and nine indirect-fired gas heaters, respectively, each heater rated for a maximum heat input capacity of approximately 28 MMBtu/hr. Each unit is expected to meet the definition of a steam generating device, per 40 C.F.R. 60.41c, and would be subject to monitoring, recordkeeping, and notification requirements but not the SO₂ and PM emission standards specified in Subpart Dc.

NSPS Subpart CCCC, Standards of Performance for Commercial and Industrial Solid Waste Incineration (CISWI) Units, applies to owners and operators of CISWI units that are constructed after June 4, 2010 or reconstructed or modified after August 7, 2013, and which meet all of the requirements specified in 40 C.F.R. 60.2010. The compressor stations and heater station would include a CISWI unit that is expected to meet the definition of a CISWI unit subject to Subpart CCCC in 40 C.F.R. 60.2265 and would not be exempt under 40 C.F.R. 60.2020. Per Subpart CCCC, a preconstruction siting analysis and waste management plan would be submitted to EPA prior to commencing construction of each CISWI unit. Commencing construction is defined by EPA as entering into an agreement to purchase a CISWI unit,

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among other actions. Subpart CCCC also requires proper operating training and qualification, emission and operating limits, performance testing and compliance monitoring, and recordkeeping and reporting requirements upon startup of each CISWI unit.

NSPS Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, applies to owners and operators of stationary CI ICE that commence construction after July 11, 2005 where the stationary CI ICE are either manufactured after April 1, 2006 and are not fire pump engines or manufactured as a certified NFPA fire pump engine after July 1, 2006. At this time, the Project plan does not include stationary CI ICE at any of the compressor stations and heater stations.

NSPS Subpart JJJJ, Standards of Performance for Stationary Spark Injection Internal Combustion Engines, applies to stationary SI ICE for which construction, modification, or reconstruction commenced after June 12, 2006. The compressor stations and heater station are planned to include SI ICE, which would be required to meet the NO_x, CO, and VOC emission limits in Table 1 of Subpart JJJJ.

NSPS Subpart KKKK, Standards of Performance for Stationary Combustion Turbines, applies to stationary combustion turbines, including any associated duct burners, with a heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBtu) per hour and for which construction, modification, or reconstruction after February 18, 2005. Each compressor station is planned to include gas-fired combustion turbines for compressor mechanical drives, each of which would have a maximum heat input at peak load (HHV) greater than 50 MMBtu/hr and less than 850 MMBtu/hr and, as such, Subpart KKKK applies to all of the combustion turbines proposed for the compressor stations. Each new gas-fired turbine is expected to be equipped with DLN/DLE emission controls and would be capable of achieving the applicable Subpart KKKK NO_x emission limits. Additionally, the new combustion turbines at the compressor stations would burn fuel gas with a sulfur content no greater than or equal to 3 ppmv S, resulting in SO₂ emissions well below the SO₂ limits in Subpart KKKK.

Subpart OOOOa, Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification, or Reconstruction Commenced after September 18, 2015 would apply to;

- Each centrifugal compressor using wet seals;
- Each single continuous bleed natural gas-driven pneumatic controller operating at a natural gas bleed rate greater than 6 standard cubic feet per hour (scfh);
- Storage vessels, as defined in 40 C.F.R. 60.4530a, with potential VOC emissions equal to or greater than 6 tons per year; and
- The collection of fugitive emissions components, as defined in 40 C.F.R. 60.5430a, at the compressor station.

The equipment and collection of fugitive emissions components at the compressor stations and heater stations would be subject to the monitoring, recordkeeping, and reporting requirements in Subpart OOOOa.

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1.2.3 Meter Stations

Information needed to make an adequate regulatory applicability determination for equipment that would be installed and operated at the meter stations is not yet available. Final applicability determinations would be made for the meter stations based on final facility design.

1.2.4 GTP

The GTP would be subject to the flare design and operating requirements of Subpart A for any flare that serves as a control device to comply with the applicable requirements for NSPS-regulated units. Subpart A restricts visible emissions from flares and requires the documentation of design data to ensure proper flare operation.

NSPS Subpart Da, Standards of Performance for Electric Utility Steam Generating Units, applies to electric utility steam generating units with a heat input capacity greater than 250 MMBtu/hr and for which construction, reconstruction, or modification commenced after September 18, 1978. The GTP would not include any steam generating units constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW net electrical output to any utility power distribution for sale and as such would not be subject to the requirements of Subpart Da.

NSPS Subpart Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units, applies to stationary source steam generating units with a heat input capacity greater than 100 MMBtu/hr and for which construction, reconstruction, or modification commenced after June 19, 1984. The preliminary design plan for the GTP includes three natural gas-fired utility heaters with a heat input of approximately 225 MMBtu/hr, each. These heaters are anticipated to be subject to the monitoring, recordkeeping, and reporting requirements and NO_x emission limits in Subpart Db. Because the planned units would fire only natural gas, each unit would be exempt from the SO₂ and PM emission limits specified in Subpart Db.

NSPS Subpart Dc, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units, applies to stationary steam generating units, as defined in 40 C.F.R. 60.41c, with a heat input capacity less than 100 MMBtu/hr and greater than 10 MMBtu/hr and for which construction, reconstruction, or modification commenced after June 9, 1989. The current GTP design plan does not include any steam generating units with a heat input capacity greater than 10 MMBtu/hr and less than 100 MMBtu/hr, each.

NSPS Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels for which Construction, Reconstruction, or Modification Commenced After July 23, 1984, applies to owners and operators of storage vessels constructed, reconstructed, or modified after July 23, 1984 with a capacity greater than or equal to 75 m³ (19,813 U.S. gallons) and used to store a volatile organic liquid, which is any organic liquid that can emit VOCs, as defined in 40 C.F.R. 51.100, into the atmosphere. Subpart Kb does not apply to storage vessels with a capacity greater than or equal to 75 m³ (19,813 U.S. gallons) but less than 151 m³ (39,890 U.S. gallons) and used to store a liquid with a maximum true vapor pressure less than 15.0 kilopascals (kPa) (2.2 pounds per square inch [absolute] (psia)). Subpart Kb also does not apply to storage vessels with a capacity greater than or equal to 151 m³ (39,890 U.S. gallons) used to store a volatile organic liquid with a maximum true vapor pressure less than 3.5 kPa (0.51 psia). Additionally, the following storage vessels are exempt from Subpart Kb per 40 C.F.R. 60.110b(d):

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- Pressure vessels designed to operate in excess of 204.9 kPa and without emissions to the atmosphere;
- Storage vessels permanently attached to mobile vehicles such as trucks, railcars, barges, or ships; and
- Storage vessels with a design capacity less than or equal to 1,589.874 m³ (420,000 U.S. gallons) used for petroleum or condensate stored, processed or treated prior to custody transfer. Custody transfer is defined in 40 C.F.R. 60.111b as the transfer of produced petroleum and/or condensate, after processing and/or treatment in the producing operations, from storage vessels or automatic transfer facilities to pipelines or any other forms of transportation.

The current GTP design plan includes a number of fuel system storage tanks that would each have a capacity less than 75 m³ (19,813 gallons) and, as such, would not be subject to Subpart Kb. The current GTP design plan also includes a triethylene glycol (TEG) storage tank with a design capacity of 100 m³ (26,500 gallons). Because TEG has a vapor pressure much less than 15.0 kPa, the TEG storage tank would not be subject to Subpart Kb.

The capacities of other storage tanks and the expected composition of the volatile organic liquid contents that would be stored at the GTP have not yet been determined. Final applicability determinations would be made for all storage tanks based on final facility design.

NSPS Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, applies to owners and operators of stationary CI ICE that commence construction after July 11, 2005 where the stationary CI ICE are manufactured after April 1, 2006 and are not fire pump engines or manufactured as a certified NFPA fire pump engine after July 1, 2006. All stationary CI ICE installed and operated at the GTP that are subject to Subpart IIII would be required to burn ULSD.

The preliminary design plan for the GTP includes:

- One non-emergency stationary CI ICE power generator rated for a maximum power output of approximately 2,500 kW and a displacement less than 10 liters per cylinder,
- One non-emergency stationary CI ICE power generator rated for a maximum power output of approximately 150 kW and a displacement less than 10 liters per cylinder,
- Three fire water pumps CI ICE that would be rated for a maximum power output of approximately 250 horsepower each and have a displacement less than 10 liters per cylinder, and
- One emergency stationary CI ICE that would be rated for a maximum power output of approximately 250 kW and have a displacement less than 10 liters per cylinder.

Each of these units must be designed to meet the applicable Subpart IIII emission limits. The emergency CI ICE is expected to be required to be in compliance with the operating and maintenance procedures specified in 40 C.F.R. 60.4211(f) and the emission limits in 40 C.F.R. 60.4205(b). Under 40 C.F.R. 60.4209(a), the three fire pump CI ICE would require the installation of a non-resettable hour meter prior

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to startup for any unit that does not meet the emission standards in Subpart IIII that are applicable to non-emergency engines.

NSPS Subpart JJJJ, Standards of Performance for Stationary Spark Injection Internal Combustion Engines, applies to stationary spark ignition internal combustion engines (SI ICE) for which construction, modification, or reconstruction commenced after June 12, 2006. Currently, the Project plan does not include SI ICE at the GTP. If any stationary SI ICE are installed at the GTP and subject to Subpart JJJJ, then the stationary SI ICE would be required to meet the NO_x, CO, and VOC emission limits in Table 1 of Subpart JJJJ per 40 C.F.R. 60.4233(e).

NSPS Subpart KKKK, Standards of Performance for Stationary Combustion Turbines, applies to stationary combustion turbines, including any associated duct burners, with a heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBtu) per hour and for which construction, modification, or reconstruction after February 18, 2005. As a result, Subpart KKKK applies to all of the combustion turbines proposed for the GTP. The preliminary GTP design plan includes eighteen gas-fired turbines for power generation and for compressor mechanical drives. Each new gas-fired turbine is expected to be equipped with DLN emission controls and would be capable of achieving the applicable Subpart KKKK NO_x emission limits. The sulfur content of the fuel gas burned in the new combustion turbines at the GTP would be low, resulting in SO₂ emissions well below the SO₂ limits in Subpart KKKK.

NSPS Subpart OOOOa, Standards of Performance for Crude Oil and Natural Gas Facilities, applies to certain components of onshore natural gas processing plants that commence construction, modification, or reconstruction after September 18, 2015. The components of the GTP that may be subject to Subpart OOOOa include:

- Each centrifugal compressor using wet seals;
- Each single continuous bleed natural gas-driven pneumatic controller;
- Storage vessels, as defined in 40 C.F.R. 60.4530, with potential VOC emissions equal to or greater than 6 tons per year;
- Sweetening units;
- Each natural gas-driven diaphragm pump; and
- The group of all equipment, except compressors, within a process unit, which is defined as components assembled for the extraction of natural gas liquids from field gas, the fractionation of the liquids into natural gas products, or other operations associated with the processing of natural gas products.

Under Subpart OOOOa, each continuous bleed natural gas-driven pneumatic controller at a natural gas processing plant must have a bleed rate of zero. Subpart OOOOa requires that such pneumatic controllers be tagged with the year and month of installation, reconstruction, or modification and identification information that allows traceability to the records for that pneumatic controller.

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Monitoring, recordkeeping and reporting requirements, and VOC emission standards for storage vessels subject to Subpart OOOOa are included at 40 C.F.R. 60.5395a. Subpart OOOOa does not apply to storage vessels subject to and controlled in accordance with the requirements for storage vessels in Subpart Kb or 40 C.F.R. Part 63 Subparts G, CC, HH, or WW.

The GTP processing unit equipment, except compressors, subject to Subpart OOOOa must meet the equipment leak standards in 40 C.F.R. 60.5400a, which cross-reference equipment leak standards in Subpart VVa, Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for which Construction, Reconstruction, or Modification Commenced After November 7, 2006.

Sweetening units installed and operated at the GTP would be subject to the SO₂ emission reduction efficiency standards under 40 C.F.R. 60.5405a, the performance test method standards under 40 C.F.R. 60.4506a, and monitoring requirements under 40 C.F.R. 60.5407a if the sweetening units have a design capacity greater than 2 long tons per day (LT/day) of hydrogen sulfide (H₂S) in the acid gas (expressed as sulfur), per 40 C.F.R. 60.5365(g)(3). Sweetening facilities producing acid gas that is completely re-injected into oil-or-gas-bearing geologic strata or that is otherwise not released to the atmosphere are not subject to the SO₂ emission and monitoring standards, initial and continuous compliance standards, and recordkeeping and reporting requirements for sweetening units in Subpart OOOOa.

Subpart OOOOa notification, reporting, and recordkeeping requirements are outlined in 40 C.F.R. 60.5420a. Additional recordkeeping requirements and reporting requirements are included at 40 C.F.R. 60.5421a and 40 C.F.R. 60.5422a, respectively, for equipment at onshore natural gas processing plants subject to the equipment leak standards in Subpart OOOOa, which include semiannual reporting requirements.

2.0 NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS (NESHAPS)

The 1970 CAA required that EPA develop health risk-based standards for regulating hazardous air pollutant (HAP) emissions. These regulations are codified in 40 C.F.R. Part 61, National Emission Standards for Hazardous Air Pollutants (NESHAPs) and apply to specific pollutants and source categories. The Project is not one of the source categories regulated under 40 C.F.R. Part 61 and, as such, the requirements of 40 C.F.R. 61 would not apply to the Project.

The 1990 CAA Amendments expanded the EPA obligation to regulate HAPs and required EPA to set technology-based standards for a larger list of HAPs and for many more source categories. These NESHAPs are codified in 40 C.F.R. Part 63, also referred to as maximum achievable control technology (MACT) standards, and regulate HAP emissions from major sources of HAPs and area sources of HAPs within specific source categories. Part 63 defines a major source of HAPs as any stationary source or group of stationary sources located within a contiguous area and under common control that has the potential to emit more than 10 tons per year (tpy) of any single HAP or more than 25 tpy of all HAPs combined. Part 63 defines an area source of HAPs as any stationary source of HAPs that is not a major source of HAPs. Preliminary HAPs emission calculations indicate that the Liquefaction Facility and the GTP are each anticipated to have the potential to emit a single HAP, formaldehyde, at a rate greater than 10 tpy. As a result, these facilities are expected to be major sources of HAPs. The compressor stations, heater stations,

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and metering station potential to emit total HAPs and any single HAP would be below the 25 tpy and 10 tpy thresholds, respectively, and would be classified as area sources of HAPs.

Subpart A of Part 63 provides the general provisions for sources subject to the various MACT standards, which includes monitoring, notification, and reporting requirements for sources subject to certain subparts within 40 C.F.R. Part 63. Each subpart provides a table identifying which general provisions apply to that subpart. A preliminary analysis of MACT standards in 40 C.F.R. Part 63 that may apply to the proposed Project facilities is provided below and summarized in Table 2. Final applicability determinations would be made based on final facility design.

TABLE 2 Preliminary NESHAPs Applicability Summary			
NESHAPs Subpart	Applicability		
	Liquefaction Facility	Compressor and Heater Stations	GTP
Subpart A – General Provisions	Yes	Yes	Yes
Subpart Y – National Emission Standards for Marine Tank Vessel Loading Operations	No	No	No
Subpart EEE – NESHAPs from Hazardous Waste Combustors	No	TBD	No
Subpart EEEE – NESHAPs for Organic Liquids Distribution (Non-Gasoline)	TBD	No	TBD
Subpart H – Organic HAPs for Equipment Leaks	TBD	TBD	TBD
Subpart HH – NESHAPs for Oil and Natural Gas Production Facilities	TBD	No	TBD
Subpart HHH – NESHAPs for Natural Gas Transmission and Storage Facilities	No	No	Yes
Subpart YYYY – NESHAPs for Stationary Combustion Turbines	Yes	No	Yes
Subpart ZZZZ – NESHAPs for Stationary Reciprocating Internal Combustion Engines	Yes	Yes	Yes
Subpart DDDDD – NESHAPs for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters	No	No	Yes
Subpart JJJJJ – NESHAPs for Industrial, Commercial, and Institutional Boilers Area Sources	No	No	No

2.1 LIQUEFACTION FACILITY

The Liquefaction Facility would be subject to the flare design and operating requirements of Subpart A for the flares if the flares serve as a control device to comply with the applicable requirements of other NESHAPs-regulated units. Subpart A restricts visible emissions from flares and requires the documentation of design data to ensure proper flare operation. Final applicability determinations for the flares would be made based on final facility design.

Subpart Y, National Emission Standards for Marine Tank Vessel Loading Operations, applies to new major sources of HAPs with marine tank vessel loading operations, which are defined in 40 C.F.R. 63.561 as any

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operation under which a commodity is bulk loaded onto a marine tank vessel from a terminal. The Liquefaction Facility marine terminal loading berths would be located more than 0.81 km (0.5 miles) from the shore and meet the criteria of an offshore loading terminal in Subpart Y. The marine terminal would not be a new major source offshore loading terminal because the potential HAP emissions exclusively from the marine terminal would be less than 10 tons per year (tpy) of any single HAP and less than 25 tpy of all HAPs combined. As a result, Subpart Y would not apply to the marine terminal.

Subpart EEEE, National Emission Standards for Hazardous Air Pollutants: Organic Liquids Distribution (Non-Gasoline), establishes emission limits, operating limits, and work practice standards for organic HAPs emitted from organic liquid distribution (OLD) operations at major sources of HAPs. Per 40 C.F.R. 63.2334(b), OLD operations at facilities subject to Subpart HH and Subpart HHH are not subject to Subpart EEEE. Subpart EEEE applies to the collection of activities and equipment used to distribute organic liquids, as defined in 40 C.F.R. 63.2406, including:

- Storage tanks storing organic liquids;
- Transfer racks at which organic liquids are loaded into or unloaded out of transport vehicles and/or containers;
- Equipment leak components in organic liquids service that are associated with storage tanks and equipment subject to Subpart EEEE;
- Transport vehicles while the vehicles are loading or unloading organic liquids at transfer racks subject to Subpart EEEE; and
- Containers while the containers are loading or unloading organic liquids at transfer racks subject to Subpart EEEE.

Storage tanks, transfer racks, transport vehicles, containers, and equipment leak components that are part of an affected source under another subpart of 40 C.F.R. 63 are exempt from Subpart EEEE. A final applicability determination for Subpart EEEE will be made based on final facility design.

Subpart H, National Emission Standards for Organic HAPs for Equipment Leaks, applies to certain equipment within a source subject to the provisions of a specific subpart in 40 C.F.R. 63 that references Subpart H. For affected equipment, Subpart H includes equipment design requirements as well as leak detection and repair for pumps, compressors, agitators, pressure-relief devices, sampling connection systems, open-ended valves or lines, valves, connectors, surge control vessels, bottoms receivers, instrumentation systems, and control devices or closed-vent systems required by Subpart H that are intended to operate in organic HAP service 300 hours or more during the calendar year.

Organic HAP service means that a piece of equipment either contains or contacts a fluid (liquid or gas) that is at least five percent by weight of total organic HAPs on an annual basis (40 C.F.R. 63.161). This definition may apply to equipment that handles hydrocarbon condensates if the hydrocarbon condensates contain concentrated amounts of organic HAPs such as hexane. The possibility exists that no equipment at the Liquefaction Facility would trigger Subpart H applicability. A final applicability determination for Subpart H would be made once detailed information about the composition of the hydrocarbon condensates anticipated at the Liquefaction Facility becomes available.

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Subpart HH, NESHAPs for Oil and Natural Gas Production Facilities, applies to facilities that process, upgrade, or store either natural gas or hydrocarbon liquids. At facilities that are major sources of HAPs, Subpart HH applies to glycol dehydration units, storage vessels with the potential for flash emissions, and the group of all ancillary equipment intended to operate in volatile HAP service at natural gas processing plants. Per 40 C.F.R. 63.761, in volatile HAP service means that a piece of ancillary equipment or compressor either contains or contacts a fluid (liquid or gas) which has a total volatile HAP concentration equal to or greater than 10 percent by weight. Ancillary equipment and compressors that are subject to Subpart H and Subpart HH would only be required to comply with the requirements of Subpart H.

The storage vessel standards in Subpart HH apply to any storage vessel that contains a hydrocarbon liquid with a stock tank gas-to-oil ratio (GOR) equal to or greater than 0.31 m³ per liter (L) and an API gravity equal to or greater than 40 degrees and an actual annual average hydrocarbon liquid throughput equal to or greater than 79,500 liters (21,000 gallons) per day. The Subpart HH storage vessel standards do not apply to storage vessels subject to 40 C.F.R. 60 Subpart Kb. An applicability determination for Subpart HH would be made based on the final Liquefaction Facility design.

Subpart HHH, NESHAP for Natural Gas Transmission and Storage Facilities, applies to owners and operators of natural gas transmission and storage facilities that transport or store natural gas prior to entering the pipeline to a local distribution company or to a final end user (if there is no local distribution company), and that are major sources of HAPs. Equipment types subject to Subpart HHH are new and existing glycol dehydration units at the natural gas transmission and storage facility and any affected glycol dehydration unit would be subject to emission control requirements in 40 C.F.R. 63.1275 and monitoring, recordkeeping and reporting requirements specified in 40 C.F.R. 63.1283 through 1285. Per 40 C.F.R. 63.1270(c), a facility that does not include any glycol dehydration units specified in 40 C.F.R. 63.1270(b) is not subject to Subpart HHH. The current Liquefaction Facility design plan does not include any glycol dehydration units so Subpart HHH would not be applicable.

Subpart YYYY, NESHAPs for Stationary Combustion Turbines, applies to existing, new, or reconstructed stationary combustion turbines at major stationary sources of HAPs. The preliminary Project plan includes six gas-fired simple cycle combustion turbines for compressor mechanical drives and four gas-fired combined cycle turbines for power generation at the Liquefaction Facility. On August 18, 2004, EPA stayed the combustion turbine NESHAP for natural gas-fired turbines. As a result, the new combustion turbines at the Liquefaction Facility would be subject to the initial notification requirements in Subpart YYYY, but need not comply with any other requirement of Subpart YYYY until EPA takes final action to require compliance and publishes a document in the Federal Register (40 C.F.R. 63.6095(d)).

Subpart ZZZZ, NESHAPs for Stationary Reciprocating Internal Combustion Engines, applies to emissions from both spark-ignition and compression-ignition reciprocating internal combustion engines at area sources and major sources. The preliminary Liquefaction Facility plan includes the following potentially affected engines:

- One non-emergency engine air compressor drive rated for a maximum power output of approximately 300 horsepower, and
- One firewater pump engine rated for a maximum power output of approximately 575 horsepower (429 kW), each.

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Under Subpart ZZZZ, a new compression ignition stationary reciprocating ICE with a site rating of less than or equal to 500 brake horsepower located at a major source of HAPs emissions can demonstrate compliance with Subpart ZZZZ by demonstrating compliance with 40 C.F.R. 60, Subpart IIII. Per 40 C.F.R. 63.6590(b)(1), the firewater pump engine would not be required to meet the requirements in Subpart ZZZZ and of Subpart A, except for the information in the initial notification requirements outlined in 40 C.F.R. 63.6645(f). All stationary diesel-fired engines at the Liquefaction Facility would be required to burn ULSD.

Subpart DDDDD, NESHAPs for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, applies to boilers and process heaters at major sources of HAPs. The current facility design plan does not include any boilers and process heaters and, as such, would not be subject to the requirements of Subpart DDDDD.

2.2 INTERDEPENDENT PROJECT FACILITIES

2.2.2 Compressor Stations and Heater Stations

Subpart EEE, National Emission Standards for HAPs from Hazardous Waste Combustors, can apply to the incineration of hazardous waste, as defined under 40 C.F.R. 261.3. The rule at 40 C.F.R. 261.4(b)(1) specifically excludes household waste, which includes any material (including garbage, trash and sanitary wastes in septic tanks) derived from households including crew quarters. The compressor stations and heater stations may include incinerators capable of burning hazardous waste. A final applicability determination would be made based on final facility design.

Subpart H, National Emission Standards for Organic HAPs for Equipment Leaks, applies to certain equipment within a source subject to the provisions of a specific subpart in 40 C.F.R. 63 that references Subpart H. Subpart H includes equipment design requirements as well as leak detection and repair requirements. Final applicability determinations to Subpart H would be made based on the final design of the compressor stations and heater station.

Subpart HH, NESHAPs from Oil and Natural Gas Production Facilities, applies to facilities that process, upgrade, or store either natural gas or hydrocarbon liquids. At facilities that are area sources of HAPs, Subpart HH applies to each triethylene glycol (TEG) dehydration unit. None of the compressor and heater stations are anticipated to include TEG units. As a result, Subpart HH would not be applicable.

Subpart HHH, NESHAP for Natural Gas Transmission and Storage Facilities, applies to owners and operators of natural gas transmission and storage facilities that transport or store natural gas prior to entering the pipeline to a local distribution company or to a final end user (if there is no local distribution company), and that are major sources of HAPs. Because the compressor stations and heater stations would be area sources of HAPs, equipment in these facilities would not be subject to Subpart HHH.

Subpart YYYYY, NESHAPs for Stationary Combustion Turbines, applies to existing, new, or reconstructed stationary combustion turbines at major stationary sources of HAPs. Subpart YYYYY defines a major source of HAPs for oil and gas production facilities in terms of the HAPs emissions from each surface site, where the compressor stations would be considered individual surface sites. Pending further design specifications, the compressor stations are not likely to be major sources of HAPs, so Subpart YYYYY would not apply to the turbines located at the compressor stations.

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Subpart ZZZZ, NESHAPs for Stationary Reciprocating Internal Combustion Engines, applies to emissions from both spark-ignition and compression-ignition reciprocating internal combustion engines at area sources and major sources of HAPs. The preliminary plan for the compressor stations and heater stations include spark-ignition reciprocating internal combustion engines. Because the engines would be located at area sources of HAPs, these engines would demonstrate compliance with the requirements of Subpart ZZZZ by complying with 40 C.F.R. 60, Subpart JJJJ.

Subpart JJJJJ, NESHAPs for Industrial, Commercial, and Institutional Boilers Area Sources, applies to industrial boilers located at an area source of HAPs. Gas-fired boilers are not subject to Subpart JJJJJ and, as such, Subpart JJJJJ would not apply to the boilers at any of the compressor stations and heater stations.

2.2.3 Meter Stations

Information needed to make an adequate regulatory applicability determination for equipment that would be installed and operated at the meter stations is not yet available and would be provided in a subsequent draft of this Resource Report.

2.2.4 GTP

The GTP would be subject to the flare design and operating requirements of Subpart A for the flares if the flares serve as a control device to comply with the applicable requirements of other NESHAPs-regulated units. Subpart A restricts visible emissions from flares and requires the documentation of design data to ensure proper flare operation.

Subpart EEEE, National Emission Standards for Hazardous Air Pollutants: Organic Liquids Distribution (Non-Gasoline), establishes emission limits, operating limits, and work practice standards for organic HAPs emitted from organic liquid distribution (OLD) operations at major sources of HAPs. Activities and equipment used to process, store or transfer organic liquids at facilities defined in Subpart HH and at facilities defined in Subpart HHH are exempt from Subpart EEEE. A final applicability determination for Subpart EEEE would be made based on final facility design.

Subpart H, National Emission Standards for Organic HAPs for Equipment Leaks, applies to certain equipment within a source, and in a service, subject to the provisions of a specific subpart in 40 C.F.R. 63 that references Subpart H. Subpart H includes equipment design requirements as well as leak detection and repair for equipment such as pumps, compressors, agitators, pressure-relief devices, sampling connection systems, open-ended valves or lines, valves, connectors, surge control vessels, bottoms receivers, instrumentation systems, and control devices or closed-vent systems required by Subpart H that are intended to operate in organic HAP service 300 hours or more during the calendar year. The possibility exists that no equipment at the GTP would be subject to Subpart H. A final applicability determination to Subpart H would be made once detailed information about the composition of the hydrocarbon condensates anticipated at the GTP becomes available.

Subpart HH, NESHAPs from Oil and Natural Gas Production Facilities, applies to facilities that process, upgrade, or store either natural gas or hydrocarbon liquids. At facilities that are major sources of HAPs, Subpart HH applies to glycol dehydration units, storage vessels with the potential for flash emissions, and ancillary equipment intended to operate in volatile HAP service at natural gas processing plants. Ancillary equipment and compressors that are subject to Subpart H and Subpart HH would only be required to comply

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with the requirements of Subpart H. An applicability determination for Subpart HH would be made based on the final GTP design.

Subpart HHH, NESHAP for Natural Gas Transmission and Storage Facilities, applies to owners and operators of natural gas transmission and storage facilities that transport or store natural gas prior to entering the pipeline to a local distribution company or to a final end user (if there is no local distribution company), and that are major sources of HAPs. The equipment subject to Subpart HHH is new and existing glycol dehydration units at the natural gas transmission and storage facility. The preliminary GTP design plan includes three parallel treatment trains, each of which would include a glycol dehydration unit that would be subject to emission control requirements specified in 40 C.F.R. 63.1275 and monitoring, recordkeeping and reporting requirements specified in 40 C.F.R. 63.1283 through 1285.

Subpart YYYY, NESHAPs for Stationary Combustion Turbines, applies to existing, new, or reconstructed stationary combustion turbines at major stationary sources of HAPs. Because the new combustion turbines at the GTP would be located on the Alaska North Slope, these combustion turbines would be exempt from the requirements of Subpart YYYY except for initial notification requirements.

Subpart ZZZZ, NESHAPs for Stationary Reciprocating Internal Combustion Engines, applies to emissions from both spark-ignition and compression-ignition reciprocating internal combustion engines at area sources and major sources. Under Subpart ZZZZ, a new compression ignition stationary reciprocating ICE with a site rating of less than or equal to 500 horsepower located at a major source of HAPs can demonstrate compliance with Subpart ZZZZ by complying with 40 C.F.R. 60, Subpart IIII. All of the stationary compression ignition reciprocating internal combustion engines at the GTP are anticipated to have a maximum power output less than 500 horsepower with the exception of one non-emergency stationary engine expected to have a maximum power output of 2,500 kW (3,353 horsepower). That larger engine would be subject to the emission limits under Subpart ZZZZ. All stationary diesel-fired engines at the GTP would be required to burn ULSD.

Subpart DDDDD, NESHAPs for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, applies to boilers and process heaters at major sources of HAPs. The preliminary design plan for the GTP includes three natural gas-fired utility heaters with a maximum heat input of approximately 250 MMBtu/hr, each, which would be affected units under Subpart DDDDD. Because these units would combust only natural gas, the units would be exempt from the emission limits specified in Table 1 of Subpart DDDDD, but would be subject to the initial notification requirements in 40 C.F.R. 63.7545 and the work practice standards in 40 C.F.R. 63.7540(a), as cross-referenced in 40 C.F.R. 63.7500.

3.0 CHEMICAL ACCIDENT PREVENTION

Section 112(r) of the 1990 CAA Amendments requires the EPA to publish regulations and guidance for chemical accident prevention at facilities for substances that pose the greatest risk of harm from accidental releases. The chemical accident prevention provisions, also referred to as the Risk Management Program (RMP), are codified in 40 C.F.R. Part 68. The regulations include a list of regulated substances that include methane, propane, and ethylene. The regulation also includes threshold quantities (TQ) for determining applicability to stationary sources. If a stationary source stores, handles, or processes one or more regulated substances in a quantity equal to or greater than the TQ specified in Table 1 of 40 C.F.R. 68.130, the facility must prepare and submit a risk management plan to EPA.

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The RMP applies only to stationary sources and, as such, does not apply to transportation subject to oversight or regulation under 49 C.F.R. Parts 192 (Federal safety standards for transportation of natural and other gas by pipeline), 193 (Federal safety standards for liquefied natural gas facilities), or 195 (Federal safety standards for transportation of hazardous liquids by pipeline), or a state natural gas or hazardous liquid program for which the state has in effect a certification to the U.S. Department of Transportation under 49 U.S.C. 60105. Transportation containers used for storage not incident to transportation and transportation containers connected to equipment at a stationary source are part of the stationary source.

Per 40 C.F.R. Part 68.115(b)(2)(iii), prior to entry into a natural gas processing plant, regulated substances in naturally occurring hydrocarbon mixtures do not need to be considered when determining whether more than a TQ of a regulated substance is present at a stationary source. Naturally occurring hydrocarbon mixtures include any combination of the following: condensate, field gas, and produced water, each as defined in 40 C.F.R. 68.3. Per 40 C.F.R. 68.3, field gas is gas extracted from a production well before the gas enters a natural gas processing plant, which is any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both, classified as North American Industrial Classification System (NAICS) code 211112, previously Standard Industrial Classification (SIC) code 1321.

A preliminary RMP applicability analysis that may apply to the proposed Project facilities is provided below and summarized in Table 3. Final applicability determinations would be made based on final facility design.

TABLE 3 Preliminary RMP Applicability Summary			
40 C.F.R. Part 68 - Chemical Accident Prevention Provisions	Applicability		
	Liquefaction Facility	Compressor and Heater Stations	GTP
Subpart F – Regulated Substances for Accidental Release Prevention	No	No	Yes

Regardless of the applicability of 40 C.F.R. Part 68 to the Project facilities, the general duty clause in Section 112(r)(1) of the CAA Amendments would still apply. That requirement reads:

“The owners and operators of stationary sources producing, processing, handling or storing such substances have a general duty in the same manner and to the same extent as section 654, title 29 of United States Code [Occupational Safety and Health Act of 1970 (29 U.S.C. 654)] to identify hazards which may result from such releases using appropriate hazard assessment techniques, to design and maintain a safe facility taking such steps as are necessary to prevent releases, and to minimize the consequences of accidental releases which do occur.”

The Project facilities would be designed and maintained to meet the general duty provisions.

3.1 LIQUEFACTION FACILITY

The hydrocarbon refrigerants and natural gas components undergoing liquefaction at the Liquefaction Facility would be subject to regulation under 49 C.F.R. Part 193, Federal Safety Standards for Liquefied

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Natural Gas Facilities and, therefore, would not be considered for determining applicability to 40 C.F.R. Part 68. The Liquefaction Facility would not include the storage of any hazardous or flammable substances in excess of a TQ determined per 40 C.F.R. 68.115 and, as such, the Liquefaction Facility would not be subject to 40 C.F.R. Part 68.

3.2 INTERDEPENDENT PROJECT FACILITIES

3.2.2 Compressor Stations and Heater Stations

The compressor stations and heater stations would be subject to regulation under 49 C.F.R. Part 192, Federal Safety Standards for Transportation of Natural and Other Gas by Pipeline. No hazardous or flammable substances in excess of a TQ determined per 40 C.F.R. 68.115 would be stored at the compressor stations or heater stations. As a result, these facilities would not be subject to 40 C.F.R. Part 68.

3.2.3 Meter Stations

No hazardous or flammable substances in excess of a TQ determined per 40 C.F.R. 68.115 would be stored at the meter stations. The meter stations would be subject to regulation under 49 C.F.R. Part 192, Federal Safety Standards for Transportation of Natural and Other Gas by Pipeline. As such, the meter stations would not be subject to 40 C.F.R. Part 68.

3.2.4 GTP

The GTP would include the storage of propane refrigerant in an amount greater than 10,000 lbs., which exceeds a TQ determined per 40 C.F.R. 68.115. The propane refrigerant stored at the GTP and would not be subject to regulation under 49 C.F.R. 192, 193, or 195 and would not be considered a component of a naturally occurring hydrocarbon mixture, as defined in 40 C.F.R. 68.3. As a result, the GTP would be subject to the provisions of 40 C.F.R. Part 68 for the storage of propane refrigerant.

Methane, ethane and propane inventories in the natural gas that would be treated at the GTP would not be subject to the provisions of 40 C.F.R. Part 68 because these substances would be components of a naturally occurring hydrocarbon mixture, as defined in 40 C.F.R. 68.3, and would not be considered for determining RMP applicability per 40 C.F.R. 68.115(b)(2)(iii).

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Alaska LNG Liquefaction Plant Construction Permit
Application

Project Information Form Attachment 5:

**Appendix D to Alaska LNG Resource Report 9
(Liquefaction Facility Air Quality Modeling Report)**

March 2018

Alaska LNG

3201 C Street, Suite 200
Anchorage, Alaska 99503

T: 907-330-6300

www.alaska-lng.com

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APPENDIX D LIQUEFACTION FACILITY AIR QUALITY MODELING REPORT



LIQUEFACTION FACILITY AIR QUALITY MODELING REPORT SUPPORTING RESOURCE REPORT NO. 9

USAL-P1-SRZZZ-00-000001-000

Rev	Date	Revision Description		Originator	Reviewer / Endorse r		Response Code	Approve r	
0	11/10/15	Issued for Use		A. MacNutt					
1	11-Oct-16	Issued for Use		A. MacNutt					
2	3/20/17	Issued for Use		B. Hoefler					
Docum ent Control No.	Countr y	Facility	Originator	Discipline	Type	Sub-Type	Location	Sequenc e	Identifie r
	US	AL	P1	S	R	ZZZ	00	000001	000

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AUTHORIZATION



ENDORSED BY:

NAME: MIKE GRAY

TITLE: AECOM PROGRAM MANAGER

DATE: OCTOBER 11, 2016

REVIEW



REVIEWED BY:

NAME: THOMAS DAMIANA

TITLE: AIR QUALITY ENGINEER

DATE: OCTOBER 11, 2016

PREPARATION



PREPARED BY:

NAME: AMANDA MACNUTT

TITLE: AIR QUALITY SCIENTIST

DATE: OCTOBER 11, 2016

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1.0 INTRODUCTION

The Alaska Gasline Development Corporation (AGDC), BP Alaska LNG LLC, ConocoPhillips Alaska LNG Company, and ExxonMobil Alaska LNG LLC (EMALL) (Applicants) plan to construct one integrated liquefied natural gas (LNG) Project (Project) with interdependent facilities for the purpose of liquefying supplies of natural gas from Alaska. The Project includes a Liquefaction Facility in Southcentral Alaska, which is the focus of this document.

As required by FERC, air dispersion modeling was utilized as a tool to demonstrate that the proposed Liquefaction Facility would comply with the National Ambient Air Quality Standards (NAAQS) and Alaska Ambient Air Quality Standards (AAAQS).

The purposes of this FERC Air Quality Modeling Report (Report) are to 1) outline the methodologies, assumptions, and input data used to conduct the air dispersion modeling analysis, and 2) provide the modeling analysis results to support discussions in Resource Report no. 9. The methodologies outlined are generally consistent with:

- Guideline on Air Quality Models, (“Modeling Guideline”) (40 CFR Part 51 Appendix W) (USEPA 2005),
- User’s Guide for the AMS/EPA Regulatory Model (AERMOD) (USEPA 2004, 2007, 2015a)
- User’s Guide for the AERMOD Terrain Preprocessor (AERMAP) (USEPA 2009a).
- Interagency Workgroup on Air Quality Modeling (IWAQM) Phase I Report: Interim Recommendation for Modeling Long Range Transport and Impacts on Regional Visibility. (IWAQM 1993).
- Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long-Range Transport Impacts (IWAQM 1998).
- Federal Land Managers’ Air Quality Related Values Work Group (FLAG): Phase I Report (USDOI 2010).
- Alaska Department of Environmental Conservation’s (ADEC) Modeling Review Procedures Manual (ADEC 2016).

Note that this report is written to address elements required by FERC for an air quality analysis as it relates to the National Environmental Policy Act (NEPA). Air quality impact analyses using dispersion modeling required by USEPA for a Prevention of Significant Deterioration application as it relates to the Clean Air Act (CAA) are generally a subset of those required for a FERC analysis.

1.1 FACILITY DESCRIPTION

The Liquefaction Facility would be a new facility constructed on the eastern shore of Cook Inlet in the Nikiski area of the Kenai Peninsula. The proposed Liquefaction Facility would be approximately 921 acres (901 acres onshore and 20 acres offshore) approximately 3 miles from Nikiski and 8.5 miles from Kenai.

While the Liquefaction Facility would be located in a relatively flat area, some higher terrain (approximately 10 to 30 meters (33 to 100 feet) higher than the facility base elevation) exists approximately 5 kilometers (3 miles) to the north. There are also several hills that peak at approximately 40 meters (130 feet) higher than the facility base elevation located about 8 kilometers (5 miles) to the east in the Kenai National Wildlife Refuge.

The coastline is immediately west of the Liquefaction Facility location where there is a bluff that is approximately 40 meters (131 feet) above the water level. Just off the coast there would be a 1,000-meter long trestle where the proposed marine terminal would be located with 2 berths that would receive periodic calls from LNG carriers.

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Figure 1-1 shows the proposed location of the Liquefaction Facility on a topographic map.

The Liquefaction Facility would be comprised of the LNG Plant and Marine Terminal. The LNG Plant would include liquefaction processing and storage facilities and necessary utilities and offsite systems, and the Marine Terminal includes the trestle(s), piping, and berthing facilities associated with liquefied natural gas carrier (LNGC) loading and berthing. Equipment at the facility would include gas-fired turbines, liquid fuel-fired reciprocating internal combustion engines, gas-fired auxiliary equipment, and flares. Diesel fuel-fired main and auxiliary engines would be located on LNG carrier vessels docked approximately 1 kilometer (3,300 feet) from the shore. Figure 1-2 provides the proposed Liquefaction Facility plot plan, with notable features indicated. The following types of emission units would be part of the Liquefaction Facility design:

- gas-fired turbines for power generation and compression,
- diesel fuel-fired fire water pumps for supplying water in case of fire
- gas-fired auxiliary air compressor to provide backup air supply in the event of a power or primary system failure,
- thermal oxidizer to control collected hydrocarbon vapors from condensate storage and loading,
- flares for control of excess gas, and
- diesel fuel-fired main and auxiliary engines located on LNG carrier vessels docked approximately 1 kilometer (3,300 feet) from the shore.

Figure 1-1: Location of Proposed Liquefaction Facility



Figure 1-2: Project Proposed Liquefaction Facility Site Plan



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2.0 APPLICABLE AIR QUALITY STANDARDS AND EVALUATION CRITERIA

Federal and state air emissions regulations are designed to ensure that new sources do not cause or contribute to an exceedance of ambient standards for criteria air pollutants. The criteria pollutants are as follows:

- Sulfur dioxide (SO₂);
- Carbon monoxide (CO);
- Nitrogen dioxide (NO₂);
- Ozone (O₃);
- Particulate matter having an aerodynamic diameter of 10 microns or less (PM₁₀);
- Particulate matter having an aerodynamic diameter of 2.5 microns or less (PM_{2.5}); and
- Lead (Pb).

As a major source, as defined under federal New Source Review (NSR) regulations, the Liquefaction Facility would be required to demonstrate by modeling that the cumulative ambient impacts would conform to established regulatory criteria for those pollutants that are emitted above the Significant Emission Rate as defined in 40 CFR 52.21(b)(23)(i). These criteria are described in the following subsections.

2.1 FEDERAL AND STATE AMBIENT AIR QUALITY STANDARDS

The U.S. Environmental Protection Agency (USEPA) has established NAAQS for these seven pollutants. The NAAQS are set at levels the USEPA believes are necessary to protect public health (primary standards) and welfare (secondary standards).

The ADEC has established similar ambient air quality standards referred to as AAAQS. AAAQS are similar to the federal NAAQS for criteria pollutants, except that ADEC has yet to remove the 24 hour and annual standards for SO₂. ADEC also has an eight hour AAAQS for ammonia. **Table 2-1** lists both the federal and state ambient air quality standards.

The federal CAA requires geographic areas that do not meet a particular NAAQS to be designated as “non-attainment” for that individual standard. Other areas can be designated as “in attainment” if data show that the area meets the standard, as “unclassified,” or as “unclassified/attainment” with respect to the standards. An area may also be designated as a “maintenance” area if it has previously been in non-attainment for a pollutant, but has since implemented a State Implementation Plan (SIP) that has brought the area back into attainment for the pollutant.

Alaska has one non-attainment area and four maintenance areas (ADEC 2016b, USEPA 2014a, and 40 C.F.R 81.302). The area surrounding the Liquefaction Facility is currently designated as attainment or unclassified for all criteria pollutants.

Table 2-1: Ambient Air Quality Standards in the Project Vicinity

Air Pollutant	Averaging Period	NAAQS	AAQs
Sulfur Dioxide	1-Hour ^a	75 ppbv (196 µg/m ³)	196 µg/m ³
	3-Hour ^b	0.5 ppmv (1,300 µg/m ³)	1,300 µg/m ³
	24-Hour ^b	NA	365 µg/m ³
	Annual	NA	80 µg/m ³
Carbon Monoxide	1-Hour ^b	35 ppmv (40 mg/m ³)	40 mg/m ³
	8-Hour ^b	9 ppmv (10 mg/m ³)	10 mg/m ³
Nitrogen Dioxide	1-Hour ^c	100 ppbv (188 µg/m ³)	188 µg/m ³
	Annual	53 ppbv (100 µg/m ³)	100 µg/m ³
Ozone	8-Hour ^d	0.070 ppmv	0.070 ppmv
Particulate Matter less than 10 Microns	24-Hour ^b	150 µg/m ³	150 µg/m ³
Particulate Matter less than 2.5 Microns	24-Hour ^e	35 µg/m ³	35 µg/m ³
	Annual ^f	12 µg/m ³	12 µg/m ³
Lead	Rolling 3-Month Average	0.15 µg/m ³	0.15 µg/m ³
Ammonia	8-Hour ^b	NA	2.1 mg/m ³

Sources: USEPA (<https://www.epa.gov/criteria-air-pollutants/naaqs-table>); ADEC 2016b

Abbreviations:

NA = not applicable

µg/m³ = micrograms per cubic meter

mg/m³ = milligrams per cubic meter

ppbv = parts per billion by volume

ppmv = parts per million by volume

Notes:

^a Standard is attained when the 3-year average of the 99th percentile of the distribution of daily maximum values is less than 75 ppbv, or 196 µg/m³.

^b Second-highest average concentration not to be exceeded more than once in a year.

^c Standard is attained when the 3-year average of the 98th percentile of the distribution of daily maximum values is less than 100 ppbv, or 188 µg/m³.

^d Three-year average of the annual fourth-highest daily maximum 8-hour average ozone concentration.

^e Standard is attained when the 3-year average of the 98th percentile of maximum values is less than 35 µg/m³.

^f Annual mean, averaged over 3 years.

2.2 PSD CLASS I AND II INCREMENTS

In addition to the NAAQS and AAAQS, air quality is regulated by the CAA through Prevention of Significant Deterioration (PSD) rules implemented in 40 CFR 52.21 and in 18 AAC 50.306. These regulations limit the future increases in ambient air concentrations of NO₂, SO₂, PM₁₀, and PM_{2.5} and establish “minor source baseline dates” for determining the date after which the air quality deterioration must be within the “PSD Increments” to the extent that the NAAQS are not exceeded. Applicable Increments are shown in Table 2-2. While the current dispersion modeling analysis is not in support of PSD permitting, FERC guidance for the preparation of Resource Report No. 9, *Air and Noise Quality*, requires evidence of a project’s ability to obtain required permits. In the case of Alaska LNG Project, this means demonstrating that the Liquefaction Facility can satisfy the source impact analysis requirements of the PSD review. As such, the dispersion modeling analysis also compared cumulative impacts to PSD Increments for informational purposes.

Table 2-2: PSD Class I and Class II Increments

Pollutant	Averaging Period	PSD Class I Increments (µg/m ³)	PSD Class II Increments (µg/m ³)
Sulfur Dioxide	1-hour	NA	NA
	3-hour ^b	25	512
	24-hour ^b	5	91
	Annual ^a	2	20
Carbon Monoxide	1-hour	NA	NA
	8-hour	NA	NA
Nitrogen Dioxide	1-hour	NA	NA
	Annual ^a	2.5	25
Particulate Matter less than 10 Microns	24-hour ^b	8	30
	Annual ^a	4	17
Particulate Matter less than 2.5 Microns	24-hour ^b	2	9
	Annual ^a	1	4
Lead	3-month rolling average	NA	NA

Abbreviations:

NA = not applicable

Notes:

^a Never to be exceeded.

^b Not to be exceeded more than once per year.

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2.3 AIR QUALITY RELATED VALUES

Air Quality Related Values (AQRVs) are resources, as defined by Federal Land Managers (FLMs), that may be adversely affected by a change in air quality, and include visibility (either regional haze or plume impairment) and sulfur and nitrogen deposition. The FLMs' AQRV Work Group (FLAG) issued a guidance document (FLAG 2010) for the methodology and AQRV criteria used to evaluate adverse impacts. This guidance and associated screening thresholds were developed primarily for Class I areas.

At the request of the FLMs, additional Class II areas deemed “sensitive” were also evaluated against Class I thresholds. Note that whether these Class II areas are in the near-field (within approximately 50 km) or the far-field (beyond approximately 50 km) changes the applicable model and AQRVs to evaluate, as in the case of visibility.

Because the AQRVs only have screening thresholds below which no concern exists, rather than regulatory standards, AQRV impacts are typically evaluated on a case-by-case basis by FLMs. As part of the impact evaluation, the FLMs consider such factors as magnitude, frequency, duration, location, geographic extent, timing of impacts and current and projected conditions of AQRVs. In practice, this methodology often results in the need to place AQRV impacts into context.

2.3.1 Plume Impairment

Plume impairment is generally defined as the pollutant loading of a portion of the atmosphere such that it becomes visible, by contrast or color difference, against a viewed background such as a landscape feature or the sky. The evaluation criteria for plume impairment are the color difference index (ΔE) and plume contrast (C_p). Plume impairment below the values in **Table 2-3** are considered negligible and no further analysis is warranted. This AQRV is generally applicable for near-field (approximately less than 50 km) source-receptor distances and modeled using the VISCREEN screening model or the PLUVUE II model if more information is required.

According to FLAG 2010, if the screening thresholds are met with VISCREEN, the FLM is likely not to object to the project on the basis of near-field visibility. If screening thresholds are not met, then use of the more refined PLUVUE II model can be implemented. The PLUVUE analysis provides additional information designed to assess the magnitude and frequency of plume impairment.

Table 2-3: Plume Impairment Initial Screening Thresholds

Model	Color Difference Index (ΔE)	Contrast (C_p)
VISCREEN level 1	2.0	0.05
VISCREEN level 2	2.0	0.05
PLUVUE II	1.0	0.02

2.3.2 Regional Haze

Visibility impairment is also manifested by the general alteration in the appearance of landscape features or the sky as the light between the observer and target becomes scattered or absorbed by pollutant loading in the atmosphere. This impairment results in a reduction of contrast between distant landscape features causing features within the landscape to disappear from the view. This AQRV is generally applicable for far-field (greater than approximately 50 km) source-receptor distances or for multiple source analyses. CALPUFF is currently the recommended model to assess regional haze impacts using methodologies and inputs described in FLAG 2010. Regional haze is evaluated by determining the change in light extinction due to pollutant loading. The criteria,

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shown in **Table 2-4**, represent the incremental increases above a reference background level. According to FLAG 2010, if the 98th percentile change in light extinction is less than 5%, the visibility threshold of concern is not exceeded. Regional haze impacts due to project sources alone that are below this threshold are considered negligible and often no further analysis is warranted.

Cumulative regional haze impacts due to both project and offsite sources are typically compared to a 10% change in light extinction. If this threshold is exceeded at an area being evaluated, the FLM may consider the impacts on a case-by-case basis by taking into account the context when making an adverse impact determination.

Table 2-4: Regional Haze Initial Screening Thresholds

Description	Change in Extinction ^a (%)
Contribute to Visibility Impairment	5
Cause Visibility Impairment	10

Notes:

^a The 98th percentile value of maximum modeled impacts, by year, for each area of concern.

2.3.3 Acid Deposition

Increased nitrogen (N) or sulfur (S) deposition may result from emissions from new facilities and have a negative impact on AQRVs sensitive to N or S deposition. Dry and wet atmospheric deposition of S and N compounds is also an AQRV that is discussed in FLAG 2010. FLMs have established Deposition Analysis Thresholds (DATs), listed in **Table 2-5**, to use as screening levels for incremental increases in S and N compounds due to a proposed facility. Facility-only deposition below the DAT of 0.005 kg/ha/yr is considered negligible.

The N and S DAT of 0.005 kg/ha/yr for the western Class I areas which are applicable to those located in Alaska is calculated as follows:

$$\text{DAT} = 0.25 \text{ kg/ha/yr} \times 0.5 \times 0.04$$

Where:

- 0.25 kg/ha/yr is the N and S western states natural background deposition value,
- 0.5 is the variability factor, representing the maximum percentage of contribution by all combined anthropogenic sources to the conservative natural background value without triggering concerns regarding impacts, and
- 0.04 is the cumulative factor, representing a four percent safety factor to protect Class I areas from cumulative deposition impacts.

Consistent with FLAG guidance, the modeled deposition flux due to Liquefaction Facility sources alone were compared to the DAT of 0.005 kg/ha/yr. However, because Liquefaction Facility sources and offsite sources were explicitly modeled to evaluate cumulative deposition, it is overly conservative to include a four percent safety factor in the DAT. Therefore, the cumulative factor was removed from the DAT and the modeled cumulative deposition flux due to the Liquefaction Facility and offsite sources was compared to a DAT of 0.125 kg/ha/yr (0.25 x 0.5). **Table 2-5** summarizes the DATs that were used in the acid deposition evaluation (see **Section 7.2.5**).

Table 2-5: Deposition Analysis Thresholds

Species	Liquefaction Facility Deposition (kg/ha/yr)	Cumulative Deposition (kg/ha/yr)
Nitrogen	0.005	0.125
Sulfur	0.005	0.125

2.3.4 Class I and Sensitive Class II Areas for Air Quality Analysis

National Conservation System Lands (NCSLs) that are Class I areas or that are considered to be Sensitive Class II areas warranting AQRV analysis were identified in consultation with the FLMS. For the Liquefaction Facility, NCSLs for AQRV evaluation identified within approximately 50 km (31 miles) for near-field analysis and between approximately 50 km to 300 km for far-field analysis are provided in **Table 2-6** and shown in **Figure 2-1**. The modeling methodology for areas within 50 km of the Liquefaction Facility and those between 50 km and 300 km (186 miles) of the Liquefaction Facility is described in **Section 6.0**.

Table 2-6: Class I and Sensitive Class II Areas included in AQRV Evaluation

	Class I Areas (approx. distance from LNG Plant)	Sensitive Class II Areas Warranting ^a AQRV Evaluation (approx. distance from LNG Facility)
Within approximately 50 km of LNG Facility (near field)	None	Kenai National Wildlife Refuge (10 km or 6 mi)
Approximately 50 km – 300 km from LNG Facility (far field)	- Tuxedni National Wildlife Refuge (86 km or 53 mi) - Denali National Park (183 km or 114 mi)	- Lake Clark National Park & Preserve (50 km or 31 mi) - Chugach National Forest (74 km or 46 mi) - Kenai Fjords National Park (92 km or 57 mi) - Kodiak National Wildlife Refuge (256 km or 159 mi)

Notes:

^a FLMS requested the evaluation of these Sensitive Class II areas.

Figure 2-1: Liquefaction Facility and Nearby Class I and Sensitive Class II Areas



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3.0 BACKGROUND AIR QUALITY

In evaluating impacts of the Liquefaction Facility with respect to the NAAQS and AAAQS, the appropriate modeled impacts were added to representative ambient background concentrations shown in **Table 3-1**.

3.1 AMBIENT DATA FOR BACKGROUND DEVELOPMENT

According to USEPA’s Guideline on Air Quality Models (USEPA 2005), background concentrations should be representative of the following in the vicinity of the source(s) under consideration:

1. Natural sources,
2. Nearby sources other than the one(s) currently under consideration, and
3. Unidentified sources.

Ambient air quality data that can be demonstrated to meet these criteria and are of PSD-quality should generally be acceptable as the basis for developing background concentrations to support modeling demonstrations.

Background concentrations were developed using data collected as part of the Alaska LNG Project Air Quality Monitoring Program located in Nikiski, Alaska (Alaska LNG, 2015). The primary objective of the monitoring program is to collect PSD-quality ambient air quality data that is representative of the region surrounding the Liquefaction Facility to support future air quality compliance demonstrations. The siting of the air quality monitoring station was approved by the ADEC on March 13, 2014 (Alaska LNG, 2015). **Figure 3-1** depicts the location of the monitoring station and its proximity to the proposed Liquefaction Facility. **Table 3-1** summarizes the full year of data available spanning January 1, 2015 – December 31, 2015.

3.2 1-HOUR NO₂ BACKGROUND DEVELOPMENT

Guidance memos published by the USEPA (2011, 2014b) outline a tiered approach to develop monitored NO₂ background values to assess compliance with the 1-hour NO₂ NAAQS. The following outlines the approaches for each tier:

First Tier Approach

Assume “a uniform monitored background contribution” by “[adding] the overall highest hourly background NO₂ concentration (across the most recent three years) from a representative monitor to the modeled design value.” This approach may be applied without further justification (USEPA 2011).

A “Less Conservative” First Tier Approach

Assume “a uniform monitored background contribution based on the monitored design value” by adding the “monitored design value from a representative monitor” to the modeled design value, based on five years of modeling. “The monitored NO₂ design value [is] the 98th-percentile of the annual distribution of daily maximum 1-hour values averaged across the most recent three years of monitored data” (USEPA 2011).

Second Tier Approach

“For shorter averaging periods, the meteorological conditions accompanying the concentrations of concern should be identified” (USEPA 2005). Assume a temporally varying background based on “multiyear averages of the 98th-percentile of the available background concentrations by season and hour-of-day, excluding periods when the source in question is expected to impact the monitored concentration” (USEPA 2011). In identifying meteorological

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conditions of concern, this tiered approach may also encompass approaches where backgrounds vary by wind direction, wind speed, day of week, or month of year as appropriate. This approach is representative “since the monitored values will be temporally paired with modeled concentrations based on temporal factors that are associated with the meteorological variability, but will also reflect worst-case meteorological conditions in a manner that is consistent with the probabilistic form of the 1-hour NO₂ standard” (USEPA 2011).

Third Tier “Paired Sums” Approach

“Combine monitored background and modeled concentrations on an hour-by-hour basis, using hourly monitored background data collected concurrently with the meteorological data period being processed by the model.” This approach is only recommended “in rare cases of relatively isolated sources where the available monitor can be shown to be representative of the ambient concentration levels in the areas or maximum impact from the proposed new source...[or] where the modeled emission inventory clearly represents the majority or emissions that could potentially contribute to the cumulative impact assessment and where inclusion of the monitored background concentration is intended to conservatively represent the potential contribution from minor sources and natural or regional background levels not reflected in the modeled inventory” (USEPA 2011).

The “less conservative” first tier approach was used to develop the 1-hour NO₂ background value used in the air quality analyses for the Liquefaction Facility. This representation of the NO₂ background value is consistent with the statistical form of the 1-hour NO₂ NAAQS. USEPA acknowledges that using the maximum hourly NO₂ concentration may be overly conservative and may reflect source-oriented impacts from nearby sources in many cases. Therefore, the agency concludes that the “less conservative” first tier approach “should be acceptable in most cases” (USEPA 2011).

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Table 3-1: Background Air Quality Data in the Vicinity of the Liquefaction Facility

Air Pollutant	Averaging Period	Concentration	
		ppbv	µg/m ³
Sulfur Dioxide	1-Hour ^a	1.9	5.0
	3-Hour ^b	1.9	5.0
	24-Hour ^b	0.9	2.4
	Period ^b	0.0	0.0
Carbon Monoxide	1-Hour ^b	1000	1145
	8-Hour ^b	1000	1145
Nitrogen Dioxide	1-Hour ^c	17.2	32.3
	Period ^b	1.4	2.6
Ozone	8-Hour ^d	47	94.0
Particulate Matter less than 10 Microns	24-Hour ^b	NA	40
Particulate Matter less than 2.5 Microns	24-Hour ^c	NA	12
	Period ^b	NA	3.7

Sources: Alaska LNG 2016a (for the period 01/01/2015 – 12/31/2015)

Abbreviations:

NA = not applicable

µg/m³ = micrograms per cubic meter ppbv = parts per billion by volume

Notes:

^a Value reported is the 99th percentile of the distribution of measured daily maximum values.

^b Value reported is the measured maximum average concentration for the period.

^c Value reported is the 98th percentile of the distribution of measured daily maximum values.

^d Value reported is the fourth-highest measured daily maximum 8-hour average ozone concentration.

Figure 3-1: Locations of Meteorological and Ambient Air Monitoring Stations



4.0 EMISSION INVENTORIES

This section will provide information regarding the emission inventories used in the dispersion modeling, which serves as an overview of the details incorporated into the emissions calculations which are provided in Appendix A.

4.1 PROJECT EMISSION UNITS

This section describes the emission data used to model Liquefaction Facility sources as well as the modeled scenarios. **Table 4-1** lists the emission units to be installed at the Liquefaction Facility and those that were considered for modeling.

Table 4-1: Equipment to be Installed at the Liquefaction Facility

Description	Number of Units
Turbines	
Gas Compression (simple – cycle)	6
Power Generation (combined – cycle)	4
Reciprocating Internal Combustion Engines (RICE) (Liquid Fired – Ultra Low Sulfur Diesel)	
Firewater Pump	1
Auxiliary Air Compressor	1
Flares	
Low Pressure (LP) Hydrocarbon flare	1
Ground Flares	3 x 50% ^a
Additional Equipment	
Thermal Oxidizer (gas-fired)	1
LNG Carrier auxiliary engines ^b (liquid-fired)	2
Tugboat auxiliary engines ^b (liquid-fired)	4

Notes:

^a 3 x 50% ground flares (3 enclosures, each capable of handling 50% of the facility flaring requirements) are installed; therefore, only two flares are expected to operate at any one time. The third flare is a back-up.

^b The main propulsion engines for the LNG carriers and tugboats are part of the Facility emissions inventory and were considered for dispersion modeling. They are not listed here because they were not part of the modeled worst-case scenario that takes place while the ships are within 500 feet of the terminal.

4.1.1 Modeled Scenarios

A conservative normal operations scenario was used to predict impacts from the Liquefaction Facility, including marine terminal activities. This scenario was selected because, when compared to other possible operating scenarios, the total emissions and assumed simultaneous equipment operation for this scenario would yield equivalent or higher modeled impacts than other scenarios. **Table 4-2** lists the operational equipment for the selected scenario alongside the equipment for those scenarios that will not be modeled.

“Normal operations” corresponds to the emissions and stack parameters that are typical for the equipment, on a per unit basis. However, the following conservative assumptions for this scenario should be noted:

- All equipment located at the Liquefaction Facility is assumed to operate concurrently, even intermittently used equipment.

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- Power generation turbines were modeled at maximum emissions rates and minimum temperature and velocity stack exit characteristics parameters.
- Even though flare relief events would only occur during maintenance or upset conditions, they were conservatively modeled as part of normal operations.
- For the marine terminal, while it is not possible for two carriers to be simultaneously loading LNG, the normal operations scenario includes the possibility that a second LNG carrier maneuvers into the open berth while one carrier is already docked and loading. While this could occur, typical operation would only include a single vessel at a time.

Modeling of the normal operations scenario was designed to be conservative, even though it is highly unlikely that all sources modeled concurrently would in fact be operating in that manner. The normal operations scenarios for the Liquefaction Facility are detailed below.

Table 4-2: List of Equipment Included in Modeled and Non-Modeled Operational Scenarios

FACILITY EQUIPMENT	SCENARIO TO BE MODELED	NON-MODELED SCENARIOS					
	(Conservative) Normal Operations	Start-up	Early Operations – Phase 1	Early Operations – Phase 2	Early Operations – Phase 3	Maintenance – Turbines & Process System	Maintenance – Flares
LNG Train 1 - 2 Compressor Turbines	Yes	Yes	Yes	Yes	Yes	Offline ^(a)	Yes
LNG Train 2 - 2 Compressor Turbines	Yes	-	-	Yes	Yes	Yes	Yes
LNG Train 3 - 2 Compressor Turbines	Yes	-	-	-	Yes	Yes	Yes
Power Gen. Turbines Set 1 (2 turbines)	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Power Gen. Turbines Set 2 (2 turbines)	Yes	-	-	-	Yes	Yes	Yes
Thermal Oxidizer	Yes	-	Yes	Yes	Yes	Yes	-
Reciprocating IC Engines	Yes	-	-	-	-	-	-
Ground Flares (2) - Pilot/Purge	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Ground Flares (spare) - Pilot/Purge (fewer emissions than flare max. relief case)	-	-	-	-	-	-	Yes
Ground Flares (2) - Max. Relief Case	Yes	-	-	-	-	-	-
Ground Flares (2) - Relief Events assoc. with Start-up (fewer emissions than max. relief case)	-	Yes	-	Yes	Yes	-	-
Ground Flares (2) - Relief Events assoc. with Turbine & Process System Maintenance (fewer emissions than max. relief case)	-	-	-	-	-	Yes	-
LP Flare - Pilot/Purge	Yes	-	Yes	Yes	Yes	Yes	Yes
LP Flare - Max. Relief Case	Yes	-	Yes	Yes	Yes	Yes	Yes
LP Flare - Relief Events assoc. with Start-up (fewer emissions than ground flare max. relief case)	-	Yes	-	Yes	Yes	-	-

Notes:

- ^a Turbines from Train 1, Train 2, or Train 3 could be offline during maintenance operations. It is likely that only a single turbine would go offline at a time, but no more than 1 full train (2 turbines) would be offline.

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4.1.1.1 Normal Operations – Liquefaction Facility

The Liquefaction Facility is designed to process product from the upstream Gas Treatment Plant Facility (GTP), using 3 process trains to compress the full throughput from the GTP. A description of the equipment that was modeled is provided below. Additional details regarding normal operation of the units as well as the development of emissions and exhaust parameters are documented in Appendix A.

Compression Turbines

The compression turbines at the Liquefaction Facility would be arranged with two turbines per train (six turbines total) to compress the refrigerant used to cool the natural gas into liquefied natural gas. The compressors would be located upstream of the refrigerant condensers and would compress the heated refrigerant gas returning from the cross exchangers used to cool the natural gas. It is assumed that the production of LNG would be relatively constant and requires a continuous supply of refrigerant. This would require the compressor turbines to operate near 100% load continuously with little variation. Therefore, modeled emissions and exhaust parameters were based on 100% operating load.

Power Generation Turbines

The Liquefaction Facility main power generation system would consist of four gas-driven turbines which would create a common power supply to all users. The power generation turbine load would fluctuate from 60% to 100%, based on the needs of the process train. Seasonal load variations would be the most common reason for differences in power generation equipment operation. During the summer months, refrigerant condensers would have a much higher energy demand, thus requiring a higher power generation turbine output.

The power generation turbines would all be equipped with Heat Recovery Steam Generators (HRSGs) for steam production at the facility. The HRSGs would operate by using the heat from the hot turbine exhaust gas to produce steam. The steam would be used by steam turbine generators within the power generation plant.

The HRSG would be designed to always accept the full exhaust flow from the compressor turbines. The HRSG would be designed to transfer the heat duty of the exhaust gas that corresponds to a temperature loss of roughly 600°F to 700°F. The typical outlet exhaust temperature of the compressor turbines would be 1000°F. The HRSG would reduce the temperature of the exhaust gas at the stack to 341°F, which was the modeled exhaust temperature.

To ensure maximum model-predicted impacts, emissions rates corresponding to 100% load were conservatively paired with stack exhaust velocities associated with 60% load.

Reciprocating Internal Combustion Engines

The auxiliary air compressor at the Liquefaction Facility would provide backup air supply to the instrument air system in the event of a power failure or primary instrument air compressor failure. It would only be operated in emergencies and for readiness testing. However, it was conservatively included in the modeling as an intermittently operated source, operating for 500 hours per year.

There would be one diesel-driven firewater pump located within the process facilities that would distribute fire water around the facility in the event of an emergency. It would only be operated in emergencies and for readiness testing. However, it was conservatively included in the modeling as an intermittently operated source, operating for 500 hours per year.

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Dry and Wet Flare

There would be three separate ground flares located at the Liquefaction Facility, each consisting of a dry and wet flare (six total flares). The 3 x 50% design capacity establishes that during any relief event, two out of the three flares would be operating at maximum capacity. One flare (wet and dry) is a spare and would not regularly operate. As part of normal operations, pilot and purge gas would be continuously combusted at the two wet flares and two dry flares and was included in the dispersion modeling.

Maximum relief events from the flares would occur infrequently and during upset conditions when other daily operating equipment would be shut down. However, air concentration and deposition modeling conservatively included maximum flaring from each of the four operational flares (i.e. two wet flares and two dry flares) in the normal operations scenario as intermittent sources, operating for 500 hours per year. Because the wet and dry flares cannot operate simultaneously, visibility modeling at Class I and Sensitive Class II areas was refined to only include maximum flaring from the dry flares. The dry flare was selected over the wet flare because emissions from the dry flare are much greater than the wet flare.

Low-Pressure Flare

An elevated low-pressure (LP) Flare would be located on land and would take most gas streams from LNG storage and loading systems and the Boiloff Gas (BOG) compression system. The LP Flare would also support marine operations by receiving all gases from warm carriers as well as tank breathing during loading activities. Lastly, if the thermal oxidizer is upset for any reason, gases from condensate storage and loading (typically incinerated by the thermal oxidizer), would be sent to the LP Flare (via blower assist).

The LP flare was modeled as a part of normal operations, assuming continuous emissions for both pilot/purge and maximum relief cases.

Thermal Oxidizer

A thermal oxidizer located at the Liquefaction Facility would combust vented hydrocarbon vapors from condensate storage and loading. The condensate and offspec condensate storage tanks, as well as the equalization tank that would help to separate oil from the facility's wastewater, would send all vent gas from working and flash losses through the thermal oxidizer. The thermal oxidizer was included in the modeling as continuously operating at 100% load.

Point source parameters and emissions rates used to model the normal operations scenario for the Liquefaction Facility are provided in **Table 4-3** and **Table 4-4**. These data were developed based on USEPA emission factors (AP-42) and vendor data, where possible. Detailed calculations are documented in Appendix A. All emission units were modeled as vertical and uncapped point sources, and all point source locations were referenced to NAD83 UTM Zone 5 coordinates.

Table 4-3: Modeled Liquefaction Facility Source Emissions

Model ID	Source Description	NO _x (g/sec)		SO ₂ (g/sec)			PM _{2.5} (g/sec)		PM ₁₀ (g/sec)		CO (g/sec)
		1-hour	Annual	1-hour	3-hour 24-hour	Annual	24-hour	Annual	24-hour	Annual	1-hour 8-hour
TURB1	Compression turbine	4.74E+00	4.51E+00	3.67E-01	3.67E-01	3.50E-01	1.04E+00	9.86E-01	1.04E+00	9.86E-01	8.02E+00
TURB2	Compression turbine	4.74E+00	4.51E+00	3.67E-01	3.67E-01	3.50E-01	1.04E+00	9.86E-01	1.04E+00	9.86E-01	8.02E+00
TURB3	Compression turbine	4.74E+00	4.51E+00	3.67E-01	3.67E-01	3.50E-01	1.04E+00	9.86E-01	1.04E+00	9.86E-01	8.02E+00
TURB4	Compression turbine	4.74E+00	4.51E+00	3.67E-01	3.67E-01	3.50E-01	1.04E+00	9.86E-01	1.04E+00	9.86E-01	8.02E+00
TURB5	Compression turbine	4.74E+00	4.51E+00	3.67E-01	3.67E-01	3.50E-01	1.04E+00	9.86E-01	1.04E+00	9.86E-01	8.02E+00
TURB6	Compression turbine	4.74E+00	4.51E+00	3.67E-01	3.67E-01	3.50E-01	1.04E+00	9.86E-01	1.04E+00	9.86E-01	8.02E+00
TRB_GEN1	Power generation turbine	1.84E+00	1.52E+00	1.36E-01	1.36E-01	1.21E-01	3.84E-01	3.40E-01	3.84E-01	3.40E-01	9.96E-01
TRB_GEN2	Power generation turbine	1.84E+00	1.52E+00	1.36E-01	1.36E-01	1.21E-01	3.84E-01	3.40E-01	3.84E-01	3.40E-01	9.96E-01
TRB_GEN3	Power generation turbine	1.84E+00	1.52E+00	1.36E-01	1.36E-01	1.21E-01	3.84E-01	3.40E-01	3.84E-01	3.40E-01	9.96E-01
TRB_GEN4	Power generation turbine	1.84E+00	1.52E+00	1.36E-01	1.36E-01	1.21E-01	3.84E-01	3.40E-01	3.84E-01	3.40E-01	9.96E-01
AUX_COMP	Auxiliary Air Compressor (RICE)	1.77E-03 ^a	1.77E-03	2.11E-05 ^a	3.69E-04	2.11E-05	1.55E-03	8.87E-05	1.55E-03	8.87E-05	2.72E-01
FPUMP	343 kW Fire Pump 1-2 (RICE)	3.25E-02 ^a	3.25E-02	4.04E-05 ^a	7.08E-04	4.04E-05	2.99E-02	1.71E-03	2.99E-02	1.71E-03	5.19E-01
FLARE_1D	Dry Ground Flare 1 Pilot/Purge	6.13E-02	6.13E-02	2.17E-03	2.17E-03	2.17E-03	2.54E-02	2.54E-02	2.54E-02	2.54E-02	2.79E-01
FLARE_2D	Dry Ground Flare 2 Pilot/Purge	6.13E-02	6.13E-02	2.17E-03	2.17E-03	2.17E-03	2.54E-02	2.54E-02	2.54E-02	2.54E-02	2.79E-01
FLARE_1W	Wet Ground Flare 1 Pilot/Purge	1.93E-02	1.93E-02	7.09E-04	7.09E-04	7.09E-04	8.00E-03	8.00E-03	8.00E-03	8.00E-03	8.79E-02
FLARE_2W	Wet Ground Flare 2 Pilot/Purge	1.93E-02	1.93E-02	7.09E-04	7.09E-04	7.09E-04	8.00E-03	8.00E-03	8.00E-03	8.00E-03	8.79E-02
DRY_MAX1	Dry Ground Flare 1 Max. Case	2.93E+01	2.93E+01	1.08E+00	3.14E+00	1.08E+00	4.44E+00	1.22E+01	4.44E+00	1.22E+01	1.17E+03
DRY_MAX2	Dry Ground Flare 2 Max. Case	2.93E+01	2.93E+01	1.08E+00	3.14E+00	1.08E+00	4.44E+00	1.22E+01	4.44E+00	1.22E+01	1.17E+03
WET_MAX1	Wet Ground Flare 1 Max. Case	6.86E+00	6.86E+00	2.51E-01	7.34E-01	2.51E-01	1.04E+00	2.85E+00	1.04E+00	2.85E+00	2.74E+02
WET_MAX2	Wet Ground Flare 2 Max. Case	6.86E+00	6.86E+00	2.51E-01	7.34E-01	2.51E-01	1.04E+00	2.85E+00	1.04E+00	2.85E+00	2.74E+02
LP_FLARE	Low Pressure Flare Pilot/Purge	9.00E-02	9.00E-02	6.36E-03	6.36E-03	6.36E-03	3.73E-02	3.73E-02	3.73E-02	3.73E-02	4.10E-01
LP_MAX	Low Pressure Flare (Max. Flow)	1.48E-01	1.48E-01	5.67E-03	3.45E-01	5.67E-03	3.55E+00	5.83E-02	3.55E+00	5.83E-02	3.92E+01
TH_OX	Thermal Oxidizer	7.57E-02	7.57E-02	2.07E-03	2.07E-03	2.07E-03	5.64E-03	5.64E-03	5.64E-03	5.64E-03	6.24E-02

Notes:

^a Intermittently operating unit, therefore emissions set equal to annual emission rate, per USEPA guidance (USEPA 2011).

Table 4-4: Modeled Liquefaction Facility Source Physical Parameters

Model ID	Source Description	Location ^a			Stack Parameters			
		UTM X	UTM Y	Base Elev.	Ht. ^b	Temp.	Vel.	Diam.
		(m)	(m)	(m)	(m)	(K)	(m/sec)	(m)
TURB1	Compression turbine	589612.04	6726290.1	38.0	64.0	794	26.2	5.79
TURB2	Compression turbine	589704.73	6726354.0	38.0	64.0	794	26.2	5.79
TURB3	Compression turbine	589477.15	6726485.3	38.0	64.0	794	26.2	5.79
TURB4	Compression turbine	589570.16	6726549.4	38.0	64.0	794	26.2	5.79
TURB5	Compression turbine	589343.13	6726679.9	38.0	64.0	794	26.2	5.79
TURB6	Compression turbine	589435.88	6726744.2	38.0	64.0	794	26.2	5.79
TRB_GEN1	Power generation turbine	589851.09	6726009.6	38.0	45.7	445	14.6	3.05
TRB_GEN2	Power generation turbine	589931.34	6726064.9	38.0	45.7	445	14.6	3.05
TRB_GEN3	Power generation turbine	590011.59	6726120.3	38.0	45.7	445	14.6	3.05
TRB_GEN4	Power generation turbine	590091.83	6726175.8	38.0	45.7	445	14.6	3.05
AUX_COMP	Auxiliary Air Compressor (RICE)	589576.44	6726013.5	38.0	3.05	746	35.1	0.203
FPUMP	343 kW Fire Pump 1-2 (RICE)	590146.73	6726056.2	38.0	3.05	760	47.9	0.203

Notes:

^a All Coordinates are UTM Zone 5 NAD 83. Modeling assumed the facility was graded at 38 meters, which is the approximate average elevation of the receptors along the fenceline (excluding locations along the immediate shore).

^b Stack height is above mean sea level.

Table 4-4: Cont. Modeled Liquefaction Facility Source Physical Parameters

Model ID	Source Description	Location ^a			Stack Parameters			
		UTM X	UTM Y	Base Elev.	Ht. ^c	Temp.	Vel.	Diam.
		(m)	(m)	(m)	(m)	(K)	(m/sec)	(m)
FLARE_1D	Dry Ground Flare 1 Pilot/Purge	589999.69	6725837.1	38.0	2.30 ^d	1,273	20.0	0.446 ^d
FLARE_2D	Dry Ground Flare 2 Pilot/Purge	590097.74	6725906.3	38.0	2.30 ^d	1,273	20.0	0.446 ^d
FLARE_1W	Wet Ground Flare 1 Pilot/Purge	590097.74	6725906.3	38.0	1.32 ^d	1,273	20.0	0.250 ^d
FLARE_2W	Wet Ground Flare 2 Pilot/Purge	589999.69	6725837.1	38.0	1.32 ^d	1,273	20.0	0.250 ^d
DRY_MAX1	Dry Ground Flare 1 Max. Case	589999.69	6725837.1	38.0	172.8 ^d	1,273	20.0	40.8 ^d
DRY_MAX2	Dry Ground Flare 2 Max. Case	590097.74	6725906.3	38.0	172.8 ^d	1,273	20.0	40.8 ^d
WET_MAX1	Wet Ground Flare 1 Max. Case	589999.69	6725837.1	38.0	86.3 ^d	1,273	20.0	19.8 ^d
WET_MAX2	Wet Ground Flare 2 Max. Case	590097.74	6725906.3	38.0	86.3 ^d	1,273	20.0	19.8 ^d
LP_FLARE	Low Pressure Flare Pilot/Purge	589999.69	6725837.1	38.0	63.4 ^e	1,273	20.0	0.541 ^e
LP_MAX	Low Pressure Flare (Max. Flow)	590097.74	6725906.3	38.0	63.4 ^e	1,273	20.0	5.26 ^e
TH_OX	Thermal Oxidizer	589339.8	6726051.8	38.0	14.3	1,255	2.7	1.52

Notes:

- ^a All Coordinates are UTM Zone 5 NAD 83. Modeling assumed the facility was graded at 38 meters, which is the approximate average elevation of the receptors along the fenceline (excluding locations along the immediate shore).
- ^b Flare stack parameters based on ADEC guidance (ADEC 2016a). ADEC guidance uses flare total heat release to calculate an "effective" stack height and stack diameter. Therefore, different operational phases (e.g. maximum, pilot/purge) will have different "effective" parameters used in the model which will differ from actual physical parameters.
- ^c Stack height is above mean sea level.
- ^d Effective release height and diameter of ground flares based ADEC guidance (ADEC 2016a). Actual physical release height is at ground level (0.0 meters).
- ^e Effective release height and diameter of low pressure flare based ADEC guidance (ADEC 2016a). Actual physical release height is 199 feet (60.7 meters).

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4.1.1.2 Normal Operations – Marine Vessels

Normal operations of the Liquefaction Facility would include liquefaction at 100 % production rate. Following FERC guidance, only those emissions occurring from marine vessel operations within 500 meters (0.3 miles) of the LNG carrier berths were explicitly modeled. Modeling marine emissions occurring only in the immediate vicinity of the berths is also the worst-case scenario because it considers the overlap of impacts from the carriers, support vessels, Liquefaction Facility, and other nearby industrial facilities.

Transit emissions from LNG carriers were excluded from the modeling because they occur beyond 500 meters from the LNG carrier berths. Furthermore, the transient nature and short duration of emissions from carriers cruising into port would translate into lower modeled impacts than the worst-case scenario selected for modeling, described in detail below. Note that while carrier transit emissions were excluded from the dispersion modeling analysis, they were included in the overall vessel ton per year emissions inventory as part of the Liquefaction Facility emissions calculations documented in Appendix A.

The modeling analysis included the following operating modes for LNG carriers:

- Maneuvering – vessel moving into or out of port,
- Cool down – stationary phase subsequent to docking,
- Hoteling – vessel is stationary at dock but not loading,
- Loading – loading LNG, and
- Purge lines – stationary phase after loading finishes, just prior to undocking.

Within 500 meters of the berths, four tugs would operate in maneuvering mode while assisting carrier docking and undocking. They were modeled as point sources positioned 50 meters (164 feet) from the carrier, with one at each end of the carrier and two along the side.

After the carrier is docked, two of the four tugs would either idle in standby or be docked, both of which would occur outside the 500 meter perimeter from the terminal. The remaining two tugs would continue in maneuvering mode throughout each call as part of guard operations or, in winter months, performing ice clearing operations. Each of the tugs performing guard/ice clearing operations was modeled as 5 separate point sources to account for the continuous movement of the vessels. One tug (five point sources) was positioned 245 meters (800 feet) to the north of the northern carrier and one tug (five point sources) was positioned 245 meters (800 feet) to the south of the southern carrier.

Because the proposed marine terminal would include two berths, the modeled scenario assumed two LNG carriers could be docked at the same time, though it is not possible for both to be loading at the same time. The narrative below describes the scenario that was modeled. This scenario is conservative because it assumes that two carriers will call at nearly the same time rather than with some lag between the two calls. Note that it is far more likely that only one carrier would call at a time. Based on a sensitivity analysis, loading activities at the northern berth resulted in the highest impacts.

Modeled Marine Scenario Description:

LNG Carrier 1 maneuvers into the southern berth with the assistance of four Tugs positioned around the ship. The carrier then docks and loads LNG while one tug remains in maneuvering mode to guard/clear ice. The other three Tugs are idling or docked beyond 500 meters. While Carrier 1 is loading, LNG Carrier 2 maneuvers into the northern berth with the assistance of four tugs positioned around the ship. Carrier 2 docks and hotels until LNG Carrier 1 is done loading. While Carrier 1 purges lines,

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Carrier 2 starts loading LNG. Carrier 1 then maneuvers out of the berth and terminal area while Carrier 2 continues to load. After loading, Carrier 2 purges lines. Two tugs continue to guard/clear ice while the other two tugs are idling or docked beyond 500 meters until Carrier 2 is ready to maneuver out of the berth. Carrier 2 maneuvers out of the berth and terminal area with the assistance of four tugs.

Worst-case short-term emissions were based on consideration of the overlapping operations of carriers and tugs for each averaging period, given the sequential order of operations outlined in the above description. The worst-case 1-hour period was determined to be when LNG Carrier 1 is purging lines (after loading) while LNG Carrier 2 is loading LNG. Annual emissions calculations included consideration of all operating modes and the 210 expected calls for a given year. Additional details regarding the development of the worst-case marine modeling scenarios are documented in Appendix A.

Note that it is expected that LNG carriers loading at the terminal would be powered mostly by internal combustion engines, rather than steam turbine powered generators. Therefore, when calculating annual emissions, it was assumed that 98% of the carriers loading at the facility are powered by Internal Combustion (IC) engines and the rest steam driven.

The short-term emissions rates for the carriers were based on the maximum possible emissions rate from either IC engines or steam turbine power generation. For NO₂ and CO, the short-term emissions from IC engines were higher and were used in the modeling. For SO₂, PM_{2.5}, and PM₁₀, short-term emissions from the steam turbines were higher and were used in the modeling.

To calculate emissions from IC engines, assumptions regarding the mix of vessel types that would be arriving at the marine terminal were needed. The types of vessels that would be used affects emissions calculations because emission factors are tied directly to the category of ship. Details regarding the mix of vessels, age of vessels, emission factors and determination of physical stack exit conditions are documented in Appendix A.

Point source parameters and emissions rates used to model normal operations of the Marine Terminal are provided in **Table 4-5** and **Table 4-6**. These data were developed based on USEPA emission factors (AP-42) and vendor data, where possible. Detailed calculations are documented in Appendix A. All emission units were modeled as vertical and uncapped point sources, and all point source locations were referenced to NAD83 UTM Zone 5 coordinates.

Table 4-5: Modeled Marine Source Emissions^a

Model ID	Source Description	NO _x (g/sec)		SO ₂ (g/sec)				PM _{2.5} (g/sec)		PM ₁₀ (g/sec)		CO (g/sec)
		1-hour	Annual	1-hour	3-hour	24-hour	Annual	24-hour	Annual	24-hour	Annual	1-hour 8-hour
LNGCAR1	LNG Carrier (South Berth)	3.08E+00	2.04E+00	9.03E-01	9.03E-01	8.70E-01	1.08E-02	2.38E-01	7.63E-02	2.70E-01	8.45E-02	6.94E+00
LNGCAR2	LNG Carrier (North Berth)	5.29E+00	2.04E+00	9.03E-01	9.03E-01	9.26E-01	1.08E-02	2.54E-01	7.63E-02	2.87E-01	8.45E-02	1.27E+01
TG_MAN1S	Tug Maneuvering, Assisting South Carrier	0.00E+00	4.24E-02	0.00E+00	0.00E+00	5.49E-05	3.06E-05	2.54E-03	1.41E-03	2.54E-03	1.41E-03	0.00E+00
TG_MAN2S	Tug Maneuvering, Assisting South Carrier	0.00E+00	4.24E-02	0.00E+00	0.00E+00	5.49E-05	3.06E-05	2.54E-03	1.41E-03	2.54E-03	1.41E-03	0.00E+00
TG_MAN3S	Tug Maneuvering, Assisting South Carrier	0.00E+00	4.24E-02	0.00E+00	0.00E+00	5.49E-05	3.06E-05	2.54E-03	1.41E-03	2.54E-03	1.41E-03	0.00E+00
TG_MAN4S	Tug Maneuvering, Assisting South Carrier	0.00E+00	4.24E-02	0.00E+00	0.00E+00	5.49E-05	3.06E-05	2.54E-03	1.41E-03	2.54E-03	1.41E-03	0.00E+00
TG_MAN1N	Tug Maneuvering, Assisting North Carrier	0.00E+00	4.24E-02	0.00E+00	0.00E+00	5.49E-05	3.06E-05	2.54E-03	1.41E-03	2.54E-03	1.41E-03	5.07E+00
TG_MAN2N	Tug Maneuvering, Assisting North Carrier	0.00E+00	4.24E-02	0.00E+00	0.00E+00	5.49E-05	3.06E-05	2.54E-03	1.41E-03	2.54E-03	1.41E-03	5.07E+00
TG_MAN3N	Tug Maneuvering, Assisting North Carrier	0.00E+00	4.24E-02	0.00E+00	0.00E+00	5.49E-05	3.06E-05	2.54E-03	1.41E-03	2.54E-03	1.41E-03	5.07E+00
TG_MAN4N	Tug Maneuvering, Assisting North Carrier	0.00E+00	4.24E-02	0.00E+00	0.00E+00	5.49E-05	3.06E-05	2.54E-03	1.41E-03	2.54E-03	1.41E-03	5.07E+00

Notes:

^a Worst-case short-term emissions were based on consideration of the overlapping operations of carriers and tugs for each averaging period. Annual emissions calculations were based all operating modes and the number of expected calls for a given year. Thus, there are cases where short-term emission rates for some modes are zero while annual emissions are greater than zero. Additional information regarding the development of the marine emissions can be found in Appendix A.

Table 4-5 Cont.: Modeled Marine Source Emissions ^a

Model ID	Source Description	NO _x (g/sec)		SO ₂ (g/sec)				PM _{2.5} (g/sec)		PM ₁₀ (g/sec)		CO (g/sec)
		1-hour	Annual	1-hour	3-hour	24-hour	Annual	24-hour	Annual	24-hour	Annual	1-hour 8-hour
TG_ICE1A	Tug guard/ice clearing south of berths	3.65E-01	2.20E-01	2.64E-04	2.64E-04	2.42E-04	1.59E-04	1.12E-02	7.32E-03	1.12E-02	7.32E-03	0.00E+00
TG_ICE1B	Tug guard/ice clearing south of berths	3.65E-01	2.20E-01	2.64E-04	2.64E-04	2.42E-04	1.59E-04	1.12E-02	7.32E-03	1.12E-02	7.32E-03	0.00E+00
TG_ICE1C	Tug guard/ice clearing south of berths	3.65E-01	2.20E-01	2.64E-04	2.64E-04	2.42E-04	1.59E-04	1.12E-02	7.32E-03	1.12E-02	7.32E-03	0.00E+00
TG_ICE1D	Tug guard/ice clearing south of berths	3.65E-01	2.20E-01	2.64E-04	2.64E-04	2.42E-04	1.59E-04	1.12E-02	7.32E-03	1.12E-02	7.32E-03	0.00E+00
TG_ICE1E	Tug guard/ice clearing south of berths	3.65E-01	2.20E-01	2.64E-04	2.64E-04	2.42E-04	1.59E-04	1.12E-02	7.32E-03	1.12E-02	7.32E-03	0.00E+00
TG_ICE2A	Tug guard/ice clearing north of berths	3.65E-01	1.27E-01	2.64E-04	2.64E-04	2.42E-04	9.21E-05	1.12E-02	4.31E-03	1.12E-02	4.31E-03	0.00E+00
TG_ICE2B	Tug guard/ice clearing north of berths	3.65E-01	1.27E-01	2.64E-04	2.64E-04	2.42E-04	9.21E-05	1.12E-02	4.31E-03	1.12E-02	4.31E-03	0.00E+00
TG_ICE2C	Tug guard/ice clearing north of berths	3.65E-01	1.27E-01	2.64E-04	2.64E-04	2.42E-04	9.21E-05	1.12E-02	4.31E-03	1.12E-02	4.31E-03	0.00E+00
TG_ICE2D	Tug guard/ice clearing north of berths	3.65E-01	1.27E-01	2.64E-04	2.64E-04	2.42E-04	9.21E-05	1.12E-02	4.31E-03	1.12E-02	4.31E-03	0.00E+00
TG_ICE2E	Tug guard/ice clearing north of berths	3.65E-01	1.27E-01	2.64E-04	2.64E-04	2.42E-04	9.21E-05	1.12E-02	4.31E-03	1.12E-02	4.31E-03	0.00E+00

Notes:

^a Worst-case short-term emissions were based on consideration of the overlapping operations of carriers and tugs for each averaging period. Annual emissions calculations were based all operating modes and the number of expected calls for a given year. Thus, there are cases where short-term emission rates for some modes are zero while annual emissions are greater than zero. Additional information regarding the development of the marine emissions can be found in Appendix A.

Table 4-6: Modeled Marine Vessel Source Physical Parameters

Model ID	Source Description	Location ^a			Stack Parameters			
		UTM X	UTM Y	Base Elev.	Ht.	Temp.	Vel.	Diam.
		(m)	(m)	(m)	(m)	(K)	(m/sec)	(m)
LNGCAR1	LNG Carrier (South Berth)	588362.60	6725207.77	0.0	45.0 ^b	589 ^c	4.2 ^d	1.68 ^b
LNGCAR2	LNG Carrier (North Berth)	588176.02	6725657.54	0.0	45.0 ^b	589 ^c	4.2 ^d	1.68 ^b
TG_MAN1S	Tug Maneuvering, assisting South Carrier	588332.80	6725273.48	0.0	10.7 ^e	589 ^c	23.0 ^f	0.460 ^e
TG_MAN2S	Tug Maneuvering, assisting South Carrier	588308.66	6725140.99	0.0	10.7 ^e	589 ^c	23.0 ^f	0.460 ^e
TG_MAN3S	Tug Maneuvering, assisting South Carrier	588375.43	6724981.83	0.0	10.7 ^e	589 ^c	23.0 ^f	0.460 ^e
TG_MAN4S	Tug Maneuvering, assisting South Carrier	588499.33	6724892.38	0.0	10.7 ^e	589 ^c	23.0 ^f	0.460 ^e
TG_MAN1N	Tug Maneuvering, assisting North Carrier	588149.50	6725723.23	0.0	10.7 ^e	589 ^c	23.0 ^f	0.460 ^e
TG_MAN2N	Tug Maneuvering, assisting North Carrier	588135.07	6725558.94	0.0	10.7 ^e	589 ^c	23.0 ^f	0.460 ^e
TG_MAN3N	Tug Maneuvering, assisting North Carrier	588189.67	6725428.53	0.0	10.7 ^e	589 ^c	23.0 ^f	0.460 ^e
TG_MAN4N	Tug Maneuvering, assisting North Carrier	588312.47	6725342.39	0.0	10.7 ^e	589 ^c	23.0 ^f	0.460 ^e

Notes:

^a All Coordinates are UTM Zone 5 NAD 83.

^b LNG carrier stack height and diameter based on values used for carriers supporting the Corpus Christi Liquefaction project (Cheniere Energy 2013), assuming the vessel stacks will be similarly sized.

^c Stacks assumed to have an economizer and steady outlet temperature of 600°F.

^d LNG carrier stack exhaust velocity based on vendor specifications for a representative engine size for fuel consumption and engine power, and an auxiliary engine load of 53%.

^e Tug stack height and diameter based on values used for tugs supporting the Corpus Christi Liquefaction project (Cheniere Energy 2013), assuming the vessel stacks will be similarly sized.

^f Maneuvering tug exhaust velocity based on vendor specifications for a representative engine size for fuel consumption and engine power, and an engine load of 75%.

Table 4-6 Cont.: Modeled Marine Vessel Source Physical Parameters

Model ID	Source Description	Location ^a			Stack Parameters			
		UTM X	UTM Y	Base Elev.	Ht.	Temp.	Vel.	Diam.
		(m)	(m)	(m)	(m)	(K)	(m/sec)	(m)
TG_ICE1A	Tug guard/ice clearing south of berths	588643.59	6724743.53	0.0	10.7 ^c	589 ^b	23.0 ^d	0.460 ^c
TG_ICE1B	Tug guard/ice clearing south of berths	588568.69	6724698.67	0.0	10.7 ^c	589 ^b	23.0 ^d	0.460 ^c
TG_ICE1C	Tug guard/ice clearing south of berths	588468.25	6724675.72	0.0	10.7 ^c	589 ^b	23.0 ^d	0.460 ^c
TG_ICE1D	Tug guard/ice clearing south of berths	588342.99	6724702.32	0.0	10.7 ^c	589 ^b	23.0 ^d	0.460 ^c
TG_ICE1E	Tug guard/ice clearing south of berths	588264.51	6724768.63	0.0	10.7 ^c	589 ^b	23.0 ^d	0.460 ^c
TG_ICE2A	Tug guard/ice clearing north of berths	588166.43	6725931.30	0.0	10.7 ^c	589 ^b	23.0 ^d	0.460 ^c
TG_ICE2B	Tug guard/ice clearing north of berths	588038.92	6725895.24	0.0	10.7 ^c	589 ^b	23.0 ^d	0.460 ^c
TG_ICE2C	Tug guard/ice clearing north of berths	587964.45	6725845.46	0.0	10.7 ^c	589 ^b	23.0 ^d	0.460 ^c
TG_ICE2D	Tug guard/ice clearing north of berths	587909.78	6725743.46	0.0	10.7 ^c	589 ^b	23.0 ^d	0.460 ^c
TG_ICE2E	Tug guard/ice clearing north of berths	587890.31	6725642.71	0.0	10.7 ^c	589 ^b	23.0 ^d	0.460 ^c

Notes:

^a All Coordinates are UTM Zone 5 NAD 83.

^b Stacks assumed to have an economizer and steady outlet temperature of 600°F.

^c Tug stack height and diameter based on values used for tugs supporting the Corpus Christi Liquefaction project (Cheniere Energy 2013), assuming the vessel stacks will be similarly sized.

^d Maneuvering tug exhaust velocity based on vendor specifications for a representative engine size for fuel consumption and engine power, and an engine load of 75%.

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4.1.2 Non-Modeled Scenarios

In addition to normal operations, there are several other reasonably foreseeable operational scenarios that were considered for dispersion modeling of the Liquefaction Facility. However, when compared to the conservative normal operations scenario described above, these scenarios would yield lower modeled impacts due to lower emissions, less equipment operating, and/or fewer operating hours. The subsections below describe these scenarios and why modeled impacts would be lower than that from the normal operations scenario. **Table 4-2** lists the operational equipment that will be included in the modeled normal operations scenario versus equipment associated with those operational scenarios that were not modeled.

4.1.2.1 Plant Start-Up

Start-up of the Liquefaction Facility would initially utilize essential power from nearby substations prior to commissioning the power generation turbines. Initial start-up of LNG Compression Train 1 would require operation of one set of power generation turbines (two turbines total, operating at 60% to 100% load depending on plant needs). Once the power generation turbines are operational, Train 1 would be brought online. Fuel gas for the power generation turbines would be sourced from local sources.

The Refrigeration System would be the first part of the train brought online, which involves purging and filling the system with propane. During this process, propane would be sent to the flare and used to ignite the wet and dry ground flare pilots as well as the LP flare pilot. The Train 1 compressor turbines would be brought online using facility fuel gas and would briefly operate at a load of 10% before quickly ramping up to 100% load.

With the initial turbines online, GTP treated gas, or an equivalent local source, would be introduced to the Gas Dehydration System at the Liquefaction Facility. Until the dehydration system is fully operational, gas produced during purging and conditioning of dehydration media would be sent to the flares. The Cold Section of the plant would be started once dehydrated treated gas is available, with additional off-spec gas sent to the flare.

Finally, once the Refrigeration System of Train 1 and the Cold Section are fully operational, liquefied gas can be produced by the facility and the Liquefied Propane Gas (LPG) Fractionation system can be brought online. The LPG Fractionation system would take the mixed hydrocarbon liquid and separate it into speciated products. The system would include a deethanizer, depropanizer, debutanizer, and an LPG Reinjection system, all of which would produce off-spec gas that would be sent to the flares. The speciated products would then be transferred to their designated storage systems. All vapors produced during the liquid introduction to the storage and loading system would be sent to the flares.

The plant start-up scenario was not included in the dispersion modeling analysis because, if modeled, it would produce lower impacts than the conservative normal operations scenario described in **Section 4.1.1**. As shown in **Table 4-2**, the normal operations scenario includes 4 more compressor turbines and 2 more power generation turbines than the plant start-up scenario. Thus, on both a short-term and long-term basis, total turbine emissions would be far greater from the normal operations scenario than the plant start-up scenario.

Operation of the compressor turbines at a 10% load will be a brief, transient, occurrence before they ramp up to 100% load. Therefore, stack parameters associated with 100% load would be appropriate for modeling either the normal operations scenario or the plant start-up scenario. Because lower load operation will be accounted for in the power generation turbine stack parameters modeled for the normal operations scenario, there would be no difference in stack parameters modeled for the plant start-up scenario. Thus, modeled dispersion of the power generation turbine exhaust would be equivalent between the two scenarios.

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The initial plant start-up of the first train scenario includes considerable gas flaring over 6 months. It has been determined that short-term emissions (24 hours or less) from the ground flares would be much less than those occurring from the maximum relief case included in the normal operations scenario. It has also been determined that the total annual emissions from the ground flares during the 6 month startup would also be much less than that from the 500 hours of maximum relief flaring rate conservatively included in the normal operations scenario.

While there would be higher flaring emissions from the LP flare during start-up than during normal operations, the normal operations scenario would still be the worst-case due to the maximum relief flaring from the ground flares conservatively included in that scenario. The maximum relief flaring emissions from the ground flares would far surpass the start-up emissions through these flares and would also surpass the additional flaring through the LP flare during start-up.

Lastly, intermittent IC engines (auxiliary air compressor and fire water pump) are not anticipated to operate for a significant amount of time during plant start-up and thus would not contribute to any modeled impacts. However, emissions from this equipment were conservatively included in the normal operations scenario.

4.1.2.2 Early Plant Operations

Early operation of the Liquefaction Facility would be dependent on the treated gas supplied from the GTP. There would be 3 phases of early operations at the Facility:

Phase 1: The production of LNG at the Liquefaction Facility would operate at 1/3 of the total capacity through one production train for approximately one year. Therefore, one compression train would be operating at 100% load (two turbines total) and one set of power generation turbines (two turbines total) would be operating. The load of the power generation turbines will depend on the needs of the plant and will range from 60% to 100%. All intermittent equipment (e.g. reciprocating IC engines) will be operational and available if needed. Flaring associated with normal pilot/purge will also occur with early normal operation of Train 1; however no additional flaring scenarios are reasonably foreseeable.

Phase 2: Train 2 start-up would commence after approximately the first year of facility operation, and would be similar to the start-up of Train 1. With Train 1 fully operational, Train 2 would come online with the 2 compressor turbines briefly operating at 10% load, then quickly ramping up to 100% load. Again, the power generation turbines would be operating according to the needs of the plant (from 60% to 100% load). All intermittent equipment (e.g. reciprocating IC engines) would be operational and available if needed, though not anticipated to be used. Flaring of relief events similar to the start-up of Train 1 will also occur, however this will not include the initial start-up of utility or common system, only flaring associated with the Refrigeration Trains.

Phase 3: After Train 2 is fully operational and the facility is processing 2/3 of normal facility throughput, start-up of Train 3 would commence, with the 2 compressor turbines at 10% load, and power generation turbines at 60% to 100%, based on plant needs. All intermittent equipment (e.g. reciprocating IC engines) would be operational and available if needed, though not anticipated to be used. Flaring of relief events associated with equipment start-up would also occur.

No scenario specific to early plant operation was included in the dispersion modeling analysis because, if modeled, it would produce lower impacts than the conservative normal operations scenario described in **Section 4.1.1**. Considering the compressor and power generation turbines, **Table 4-2** shows that all phases of the early plant operations scenario include fewer turbines and/or lower turbine loads than the normal operations scenario which would result in lower emissions and lower modeled impacts on both a short-term and long-term basis.

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Similar to the plant start-up scenario, there would be no difference in turbine stack parameters between the normal operations and early plant operations scenarios, thus modeled dispersion of the exhaust would be equivalent between the two scenarios. Furthermore, the early operations scenario includes a lower amount of flared gas than the normal operations scenario. Lastly, intermittent IC engines are not anticipated to operate during early plant operations and thus would not contribute to any modeled impacts. However, emissions from this equipment were conservatively included in the normal operations scenario.

4.1.2.3 Early Marine Terminal Operations

Both marine terminals would be commissioned during the initial startup of the facility and Train 1 however, the first LNG Carrier vessels would not arrive to the Facility until LNG has been produced and sent to the LNG Storage Tanks which would occur during Phase 1 of early operation. Once LNG carrier calls begin, normal marine operations would commence. At that point, there is no difference in source assumptions from what is included in the normal operations scenario. The only difference is in the annual number of calls. With the plant operating at less than a 100% production rate, there would be fewer annual carrier calls during the early operations scenario than during normal operations and thus fewer annual emissions. Therefore, on a short-term and long-term basis, the normal operations scenario for marine vessels described above is the worst-case for dispersion modeling. There are no other reasonably anticipated marine scenarios that would deviate from normal operations and require a separate air quality dispersion modeling assessment.

4.1.2.4 Maintenance Operations

Turbines and Process Systems

The LNG train compressor turbines and power generation turbines would need maintenance roughly every 3 years. The duration of the maintenance event would range between 2 to 8 weeks. Process system maintenance and shutdown (heat exchangers, columns, air coolers, etc.) would coincide with turbine maintenance. During maintenance events, the equipment would be purged of gas and opened to the atmosphere for operator inspection. Once the equipment can come back online, the equipment would need to be purged of the air by an inert gas before feed gas can be reintroduced to the system. The purge gas and the initial feed gas will be sent to the flare while the equipment is brought back online.

While a turbine is being shut down, there would be an increase in uncontrolled emissions when the turbine drops below the load where the control technology functions on its way to zero load. The control technology will stop functioning somewhere below approximately 50% turbine load. Turbine operation outside of the control technology functional range would be a brief, transient occurrence that would not be explicitly modeled.

Because maintenance of equipment systems and trains would be staggered to maintain as high of the facility capacity as possible, it is likely that only one turbine would be taken offline at a time. Therefore, it is anticipated that not more than one train (2 turbines) would go offline at any time. Note that maintenance at the Liquefaction Facility may be synchronized with maintenance at the GTP to keep the treated gas and LNG production coordinated.

The maintenance operations scenario for the turbines and process systems would not produce higher modeled impacts than the normal operations scenario because there would be less equipment operating as shown in **Table 4-2**. While relief flaring would occur, the amount of gas would not be greater than from the maximum relief scenario that is included in the normal operations scenario. Therefore, the maintenance operations scenario for turbines will not be modeled.

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Flares

The flare configuration is 3 x 50%, where each flare would be capable of handling 50% flaring capacity from the entire facility. The third flare would be completely offline when not in use, meaning no fuel gas supplied for line purging and no fuel gas supplied for pilot gas. When maintenance or shutdown of one of the operating flares is required (every 5 to 10 years), the spare flare would need to come online before the other flare is shut down. This overlap would result in purge/pilot emissions from all three flares for a day or two. The operations for the remainder of the equipment at the facility would not deviate from the Normal Operations scenario.

Maintenance operations for the flares were not explicitly modeled because impacts would be less than that for the normal operations scenario. While maintenance operations include pilot/purge operation from an additional flare over the normal operations scenario, there are no emissions due to maximum relief flaring during flare maintenance. On both a short-term and long-term basis, the emissions due to the maximum relief flaring from two ground flares (conservatively included during normal operations) are far greater than pilot/purge emissions from a single flare.

4.1.2.5 Seasonal Effects on Emissions

Power Generation Turbines

Winter operation of the facility requires less power than the summer operation due to reduced demand from the Air Coolers within all systems. During the winter, operation of the power generation turbines may be at a decreased load, or even result in one of the power plants (two turbines) being taken offline. A power plant would be taken offline if the load required by the facility drops to a level that would require all four turbines to operate outside of the stable operation load range. The power generation turbines are designed to be operating in a load range from 60% to 100%, with optimal design being 85% on all turbines. The number of turbines would be reduced until the outlet power required by the facility could be produced from the remaining turbines within their stable operation load range. The normal operations scenario includes all four turbines at their maximum emission rates throughout the year. Therefore, the scenario that was modeled is more conservative than this reduced operating scenario and these seasonal effects do not need to be explicitly modeled.

4.1.3 Construction Emissions

Construction of the Liquefaction Facility would occur over an estimated eight year span, beginning in the second year following project authorization. Construction activities begin with site clearing and stabilization, roadway and surface preparation and construction, and include heavy equipment associated with scrapers, dozers, trenching, and stockpiling soil and bedrock. A worker camp would be constructed and operated during most of this construction period, and could include sources related to power generation, incineration, food preparation and refrigeration, heating, ventilation, and air conditioning. Site construction would include use of heavy equipment such as cranes and heavy transport vehicles, concrete and asphalt batch plants, additional excavation, welding, seasonal heaters, and the use of power equipment such as engines associated with pneumatic systems, power generation, and support of construction camp activities.

Construction of the Marine Terminal operations would begin at the same time as the Liquefaction Facility, but would span a four-year period. Many construction activities would take place from barges and tugs, and would include cranes, loaders, pile drivers and other support vehicles and operations.

Depending on the type of activity, construction of the Liquefaction Facility and Marine Terminal would occur on different temporary time scales from several months to several years and would be spread over multiple locations around the proposed site. Given these complexities, it is not possible

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to predict with precision which of these activities will actually overlap in time, or to know the relative locations of the associated equipment for different activities when they do overlap. These limitations would pose great difficulties for any attempt to predict ambient air quality impacts due to emissions from such equipment by means of standard dispersion models. Such models have been designed to estimate impacts from stationary sources, and the usefulness of their predictions is substantially diminished when detailed information on emission source geometry and temporal patterns cannot be provided.

The only recourse for modeling with incomplete emission source data is to resort to hypothetical worst-case assumptions that produce the highest possible predicted impacts for each of the averaging times covered in the ambient air quality standards. This approach is very likely to over-predict actual impacts by a wide margin, which is contrary to the purpose of the impact analysis. Also, by providing only absolute maximum impact estimates, such results are particularly unsuitable for comparison with several of the short-term NAAQS/AAQS that are based on multiple-year averages of certain percentile concentrations.

The difficulties described above, in addition to the fact that construction emissions are not subject to the same federal and state permitting rules as operational emissions, help to explain why dispersion modeling has not been used to characterize construction air quality impacts in any of the recent NEPA documents that have been prepared by the FERC for other LNG projects across the U.S. Following the same logic, construction activities were not modeled but rather to propose mitigations and best management practices (BMPs) for controlling construction emissions. Some BMPs that will be developed and submitted for FERC review include:

- Construction emission control plan
- Fugitive dust control plan
- Open burning control plan.

While construction activities were not included in the dispersion modeling analyses, the construction operations and construction camp activities were included in the criteria pollutant emissions documented in one of the other appendices to Resource Report no. 9.

4.2 OFFSITE SOURCES

4.2.1 Near-Field Existing Sources

In addition to modeling sources associated with the Liquefaction Facility, the dispersion analysis also addressed the cumulative ambient air quality impacts from the proposed facility and nearby offsite sources. The following lists the offsite sources included in the analysis; **Figure 1-1** shows their locations:

- Tesoro Refinery
- Existing ConocoPhillips Company (COP) Kenai LNG Facility (including ships)
- Tesoro Kenai Pipe Line (KPL) Marine Loading Terminal (including ships)
- Homer Electric Association (HEA) Bernice Lake Power Plant
- Agrium Kenai Nitrogen Plant and Loading Terminal (including ships) (Agrium)
- Homer Electric Association (HEA) Nikiski Generation Plant

No other sources were explicitly modeled because they were either not expected to produce a significant concentration gradient in the impact area or were included as part of the background concentration.

Table 4-7 lists the data sources used to develop modeling inputs for the offsite sources.

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4.2.2 Far-Field Existing Sources

In addition to the above near-field sources, the far-field modeling analysis also included existing sources not close enough to cause a significant concentration gradient in the near-field, but which could create such gradients within the far-field modeling domain. **Figure 4-1** lists the sources included in the modeling and displays their proximity to Class I and Sensitive Class II areas as well as the proposed Liquefaction Facility. Table 4-7 lists the data sources used to develop the modeling inputs for the far-field existing offsite sources. Additional details regarding the development of modeled emissions and parameters can be found in Appendix A.

4.2.3 Reasonably Foreseeable Development

In order to ensure that potential impacts in the Class I and Sensitive Class II areas would be fully addressed, the ADEC was contacted regarding other new projects throughout the state that are currently engaged in the permitting process or in construction, and may become operational over the next several years. Lists of such projects were developed following review of Resource Report No. 1 and in consultation with ADEC for the modeling domain containing the Liquefaction Facility. **Figure 4-1** lists the Reasonably Foreseeable Development (RFD) sources included in the modeling and displays their proximity to Class I and Sensitive Class II areas as well as the proposed facility. Table 4-7 lists the data sources used to develop the modeling inputs for the far-field existing offsite sources. Details regarding the development of modeled emissions and parameters can be found in Appendix A.

Note that compressor and heater stations associated with the Project pipeline were not included as RFD sources and were not modeled as part of the cumulative impact analysis. This is because emissions from these Project sources would not be large enough to significantly contribute to maximum far-field impacts dominated by the Liquefaction Facility nor are impacts from these sources likely to be collocated in space and time with those from the Liquefaction Facility. Furthermore, the Project is submitting a separate near-field air quality analysis to specifically address impacts from those compressor and heater stations that are close enough to Class I and Sensitive Class II areas to warrant modeling obviating the need to address them in this analysis.

Figure 4-1: Locations of Far-Field Existing and Reasonable Foreseeable Development Sources

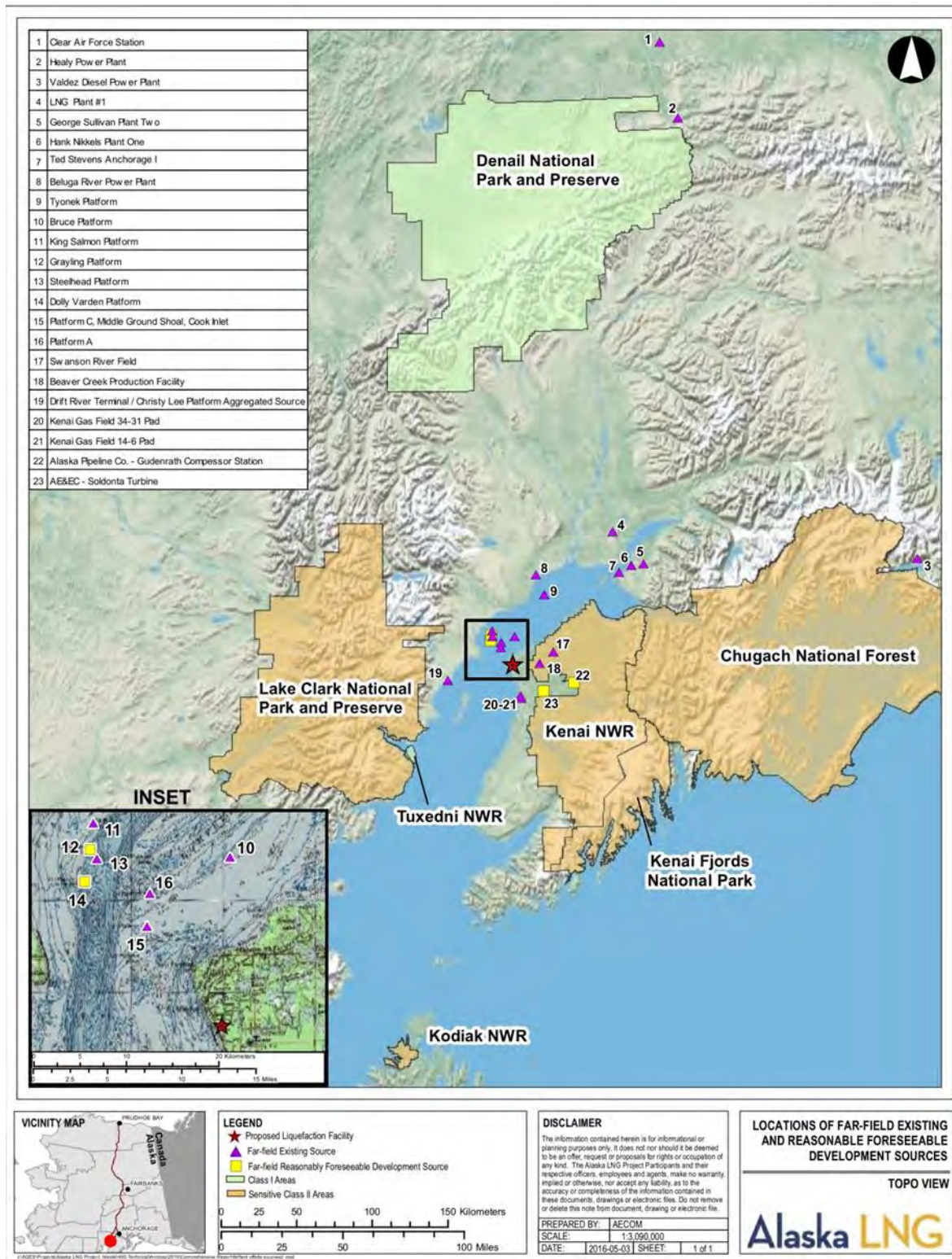


Table 4-7: Source of Modeling Inputs for Offsite Facilities

Facility	Source of Data Used in Dispersion Modeling			PSD Increment Consumption	
	Stack Locations	Emissions	Stack Parameters		
Tesoro Refinery	Dispersion modeling submitted to ADEC (Tesoro Refinery 2004), with some adjustments based on Google Earth aerial photography and elevations.	Vessel: "Cook Inlet Vessel Traffic Study" (Cape International 2012) and "Current Methodologies in Preparing Mobile Source Port-Related Emission Inventories Final Report "(USEPA 2009b). All other sources: 2011 National Emissions Inventory (NEI 2011), except maximum permitted emissions for those sources not found in the NEI.	Vessel: Parameters equivalent to Alaska LNG carrier due to lack of additional information. All other sources: Information reported to ADEC and posted to their website for public use. (http://dec.alaska.gov/Applications/Air/airtoolsweb/PointSourceEmissionInventory).	NO ₂ : SO ₂ : PM ₁₀ : PM _{2.5} :	Partial Partial Partial Partial
Kenai LNG Facility	Plot plans approved for use on the Alaska LNG project in 2014.	Vessel: Emissions equivalent to Alaska LNG carrier due to lack of additional information. All other sources: 2011 National Emissions Inventory (NEI 2011).	Vessel: Parameters equivalent to Alaska LNG carrier due to lack of additional information. All other sources: Dispersion modeling submitted to ADEC in March 2004 (Tesoro Refinery 2004), stack orientations determined by site photography.	NO ₂ : SO ₂ : PM ₁₀ : PM _{2.5} :	Partial Partial Partial No
KPL Marine Loading Terminal	Dispersion modeling submitted to ADEC (Tesoro Refinery 2004).	2011 National Emissions Inventory (NEI 2011).	Dispersion modeling submitted to ADEC (Tesoro Refinery 2004).	NO ₂ : SO ₂ : PM ₁₀ : PM _{2.5} :	Partial Partial Partial No
Bernice Lake Power Station	Dispersion modeling submitted to ADEC (Tesoro Refinery 2004).	2011 National Emissions Inventory (NEI 2011).	Dispersion modeling submitted to ADEC (Tesoro Refinery 2004).	NO ₂ : SO ₂ : PM ₁₀ : PM _{2.5} :	No Yes Yes No
Agrium	Dispersion modeling information submitted to ADEC supporting the Agrium permit application (Agrium 2014).			NO ₂ : SO ₂ : PM ₁₀ : PM _{2.5} :	Yes Yes Yes Yes
Nikiski Generating Station	Dispersion modeling information submitted to ADEC supporting the Agrium permit application (Agrium 2014).			NO ₂ : SO ₂ : PM ₁₀ : PM _{2.5} :	No No No No

Table 4-7 Cont. Source of Modeling Inputs for Offsite Facilities

Facility	Source of Data Used in Dispersion Modeling			PSD Increment Consumption
	Stack Locations	Emissions	Stack Parameters	
Far-Field Existing Facilities	Primary Data Source: 2011 National Emissions Inventory (NEI 2011). Secondary Data Source: For facilities not in the NEI, the ADEC point source database (ADEC 2011) was used.	Primary Data Source: 2011 National Emissions Inventory (NEI 2011). Secondary Data Source: For facilities not in the NEI, the ADEC point source database (ADEC 2011) was used.	All facilities modeled as volume sources with release height of 10 m, sigma-y of 2.33 m and sigma-z of 2.33 m.	Appendix A lists the PSD consumption status for each facility.
Reasonably Foreseeable Development Facilities	Permit documents available at: http://dec.alaska.gov/Applications/Air/airtoolsweb/AirPermitsApprovalsAndPublicNotices	Permit documents available at: http://dec.alaska.gov/Applications/Air/airtoolsweb/AirPermitsApprovalsAndPublicNotices	All facilities modeled as volume sources with release height of 10 m, sigma-y of 2.33 m and sigma-z of 2.33 m.	NO ₂ : Yes SO ₂ : Yes PM ₁₀ : Yes PM _{2.5} : Yes

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5.0 NEAR-FIELD MODELING METHODOLOGY

This section describes the methodology used to model the Liquefaction Facility and background source emissions with the purpose to assess ambient concentrations to a distance of 20 kilometers (12.5 miles).

5.1 MODEL SELECTION

Selection of the appropriate dispersion model for use in the required ambient air quality impact analysis is based on the available meteorological input data, the physical characteristics of the emission units that are to be simulated, the land use designation in the vicinity of the source under consideration, and the complexity of the nearby terrain. The USEPA-approved American Meteorological Society/USEPA Regulatory Model (AERMOD) modeling system was used to assess the potential ambient impacts from the proposed Liquefaction Facility. AERMOD is recommended for use in modeling multi-source emissions, and can account for plume downwash, stack tip downwash, and point, area, and volume sources (USEPA 2004, 2007). AERMOD also has the ability to simulate impacts at both flat and complex terrain receptors.

The version numbers of the AERMOD model and pre-processors that were used include:

- AERMAP version 11103
- AERMET version 15181
- AERMOD version 15181
- Building Profile Input Program, PRIME version (BPIPPRM) version 04274

5.2 MODEL OPTIONS

AERMOD model input options for Liquefaction Facility sources were set to their regulatory default values (USEPA 2015a) with the exception of the NO₂ modeling methodology, discussed below in **Section 5.7**.

The BETA AERMOD model option was used for all averaging periods and pollutants in the cumulative modeling to apply USEPA-recommended adjustments to buoyancy and dispersion for the horizontal firewater pump stacks and capped boiler stacks located at the Kenai LNG offsite facility. These adjustments were invoked in AERMOD through the use of the POINTHOR and POINTCAP keywords.

The use of these non-default BETA options currently requires case-by-case approval from USEPA. However, ADEC prefers applicants use these options as it ensures correct adjustments are made to stack characteristics and prevents any errors that could be made by manually implementing the stack adjustments (ADEC 2016a). Note that USEPA has proposed these options be adopted as regulatory defaults options in their recently proposed revisions to the Modeling Guideline (USEPA 2015b).

5.3 METEOROLOGICAL DATA

Hourly meteorological data used for air quality dispersion modeling must be spatially and climatologically representative of the area of interest and should be both laterally and vertically representative of the plume transport and dispersion conditions. The Modeling Guideline recommends a minimum of one year of site-specific meteorological data or five consecutive years of representative data collected at the nearest National Weather Service (NWS) station. Required surface meteorological data inputs to the AERMOD meteorological processor (AERMET) include, at a minimum, hourly observations of wind speed, wind direction, temperature, and cloud cover (or

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solar radiation and low-level vertical temperature difference data in lieu of cloud cover). Morning upper air sounding data from a representative NWS station are also required to generate daytime convective parameters and a complete meteorological dataset.

AERMOD-ready meteorological input files for Kenai, Alaska for 2008-2012 are pre-approved for use by ADEC for projects located in Nikiski. However, because the data are observed at a single 8-meter level, a separate study was conducted to assess whether the data are representative of the transport and dispersion conditions at the level of plumes released from the tallest stacks that would be installed at the Facility (e.g. 64 meters). The study focused on the tallest stacks since it is widely accepted that 8-meter, National Weather Service surface data can be used to represent releases from levels up to about 30 meters (100 feet).

For stacks higher than 30 meters, the study compared modeled impacts using the 8-meter Kenai meteorological data versus multi-level (up to 60 meters, 200 feet) meteorological data collected at Nikiski as input to AERMOD. The multi-level data used in the study were recorded at a tall tower located adjacent to the northern Facility fence line (Alaska LNG, 2015). Due to the similarity in modeled impacts, the study concluded that transport and dispersion conditions for tall stacks can be adequately characterized by AERMOD using the single level 8-meter Kenai data and that the Kenai data were appropriate to use for dispersion modeling of the Liquefaction Facility sources.

Additional information regarding the processing of the Kenai 2008-2012 dataset is available at http://dec.alaska.gov/air/ap/AERMOD_Met_Data.htm. Prior to use in dispersion modeling, the files were reprocessed using the current version of the AERMET processor (version 15181), as the files were originally developed using an older version of AERMET.

5.3.1 Surface Data

AERMOD-ready meteorological files were developed using surface data from the Kenai National Weather Service (NWS) station located near the Kenai Airport. Hourly surface data for Kenai NWS that were input to AERMET were supplied by ADEC. **Table 5-1** lists the joint data capture for each of the five years. **Figure 3-1** shows that the Kenai NWS station is approximately 12 kilometers (7.5 miles) to the southeast of the Liquefaction Facility location. **Figure 5-1** shows a wind rose for the model-ready 2008-2012 meteorological data.

Table 5-1: Meteorological Input Data Percent Missing Hours after Processing with AERMET

Modeled Period	Year, % Missing				
	2008	2009	2010	2011	2012
Quarter 1	0	0.32	0.05	0.05	0.05
Quarter 2	0	0.05	0.05	0.18	0.14
Quarter 3	7.65	0	1.18	1.13	0
Quarter 4	0.41	0.45	0.41	0.95	1.09
Annual	2.03	0.21	0.42	0.58	0.32

5.3.2 Upper Air Data

The temperature structure of the atmosphere prior to sunrise is required by AERMET to estimate the growth of the convective boundary layer for the day. AERMET uses the 1200 Greenwich Mean Time upper air sounding from the nearest NWS upper air observing station for this purpose. The nearest NWS station to the proposed facility that collects upper air sounding data is in Anchorage located approximately 94 kilometers (58 miles) northeast of the proposed facility. Upper air data from Anchorage concurrent with the surface data were supplied by ADEC and used as input to AERMET.

5.3.3 Surface Characteristics

Surface characteristics, including surface roughness length, Bowen ratio, and albedo, must be provided to AERMET. A summary of the surface characteristics used as input to AERMET is provided in **Table 5-2**. These data were included in the AERMOD-ready data files supplied by ADEC. **Figure 5-2** shows the land cover in the vicinity of the proposed facility and the Kenai NWS station.

5.3.4 Use of Vertical Wind Speed Standard Deviation (sigma-w) Measurements

Additional data processing is performed for site-specific sigma-w measurements that are extremely low (near or at zero and below instrument threshold values). Following recommendations provided by USEPA's AERMOD modeling contractor, any reported values of site-specific sigma-w below 0.1 m/s are set to missing so as to avoid an anomalous problem in the model that can be caused by inappropriate input data.

This processing is generally only applicable to site specific data, if collected. Sigma-w is an optional parameter that was not collected at Kenai NWS. Therefore, the additional data processing was not required for the Liquefaction Facility air quality analyses.

Table 5-2: Surface Characteristics for AERMET Processing

Surface Parameter	Spring Value ^a	Summer Value ^a	Autumn Value ^a	Winter Value ^a
Albedo	0.143	0.145	0.152	0.406
Bowen Ratio	0.509	0.395	0.658	0.426
Surface Roughness Length (meters)				
Sector 1 (30 - 60)	0.071	0.112	0.071	0.005
Sector 2 (60 - 90)	0.138	0.197	0.138	0.022
Sector 3 (90 - 120)	0.140	0.176	0.140	0.045
Sector 4 (120 - 150)	0.141	0.177	0.141	0.046
Sector 5 (150 - 180)	0.073	0.109	0.073	0.008
Sector 6 (180 - 210)	0.050	0.069	0.050	0.008
Sector 7 (210 - 240)	0.036	0.060	0.036	0.002
Sector 8 (240 - 270)	0.078	0.104	0.078	0.019
Sector 9 (270 - 330)	0.034	0.050	0.034	0.004
Sector 10 (330 - 30)	0.045	0.065	0.045	0.005

Notes:

- ^a Winter is defined as November through, spring is defined as April through May, summer is defined as June through August, and autumn is defined as September through October.

Figure 5-1: Wind Rose for 2008-2012 Kenai Meteorological Data

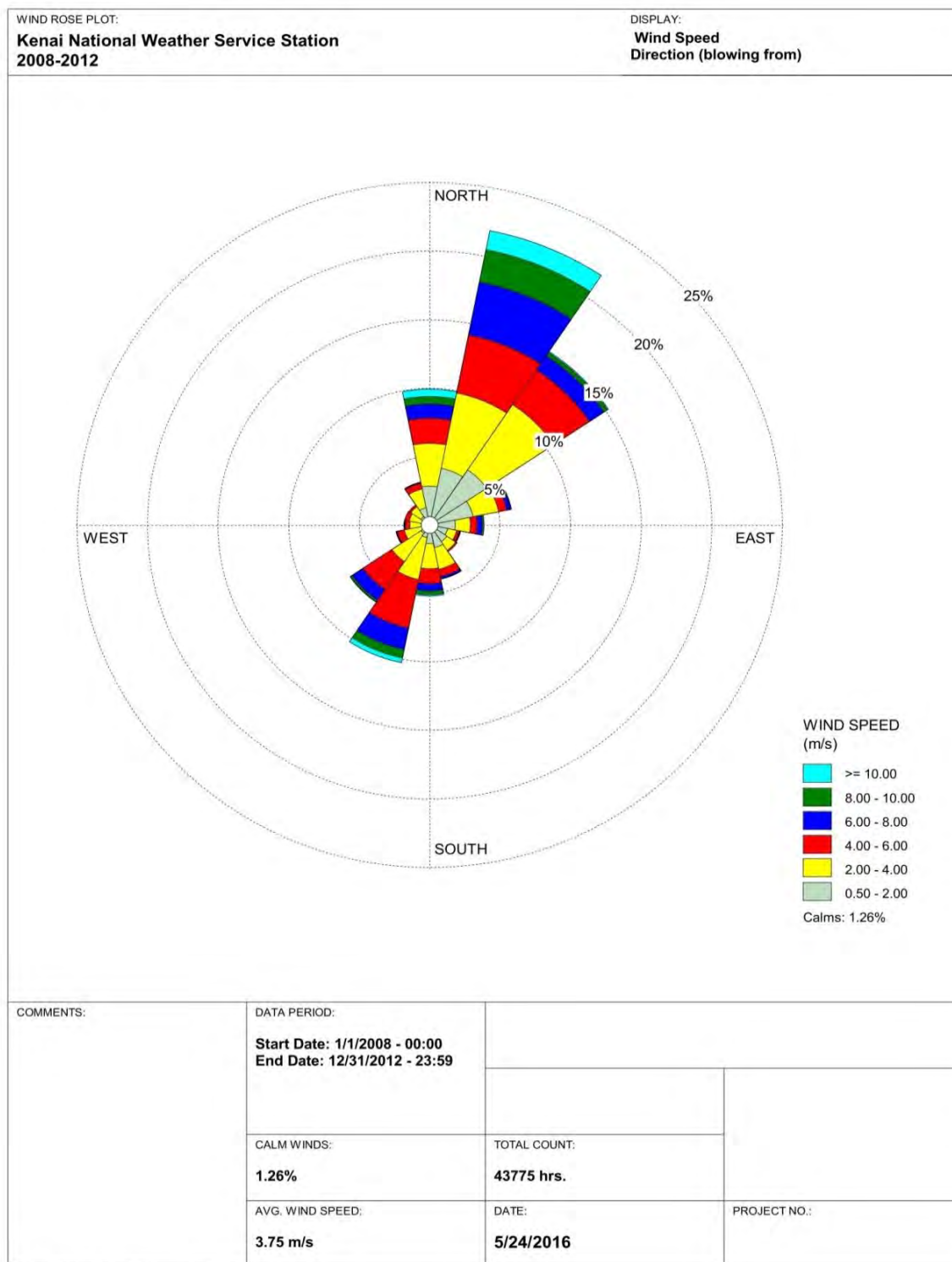
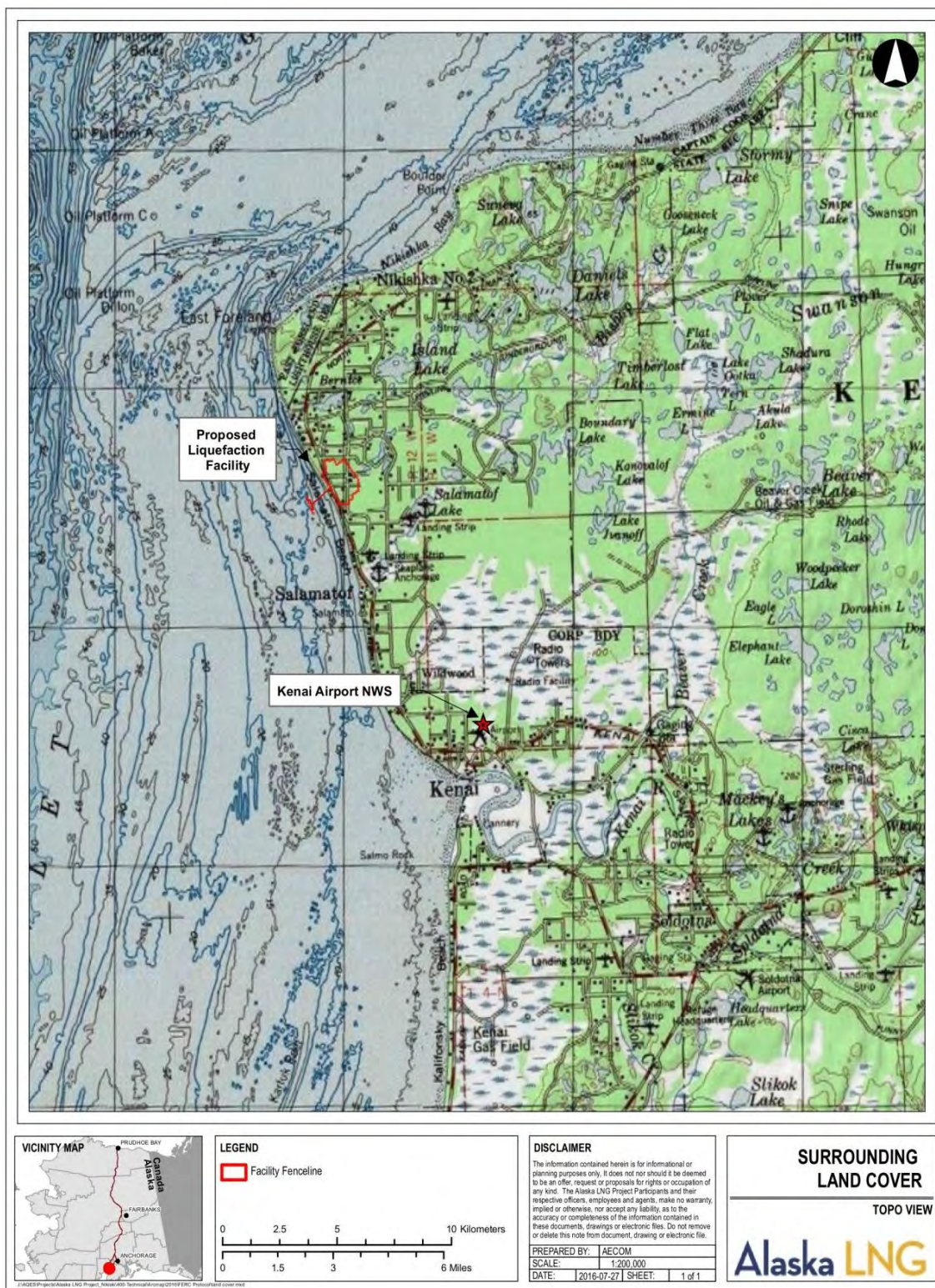


Figure 5-2: Land Cover Surrounding the Kenai NWS Location



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5.4 RECEPTORS

USEPA regulations define ambient air as “that portion of the atmosphere, external to buildings, to which the general public has access” (40 CFR 50.1(e)). For the purposes of dispersion air quality modeling, the ambient air quality boundary is typically set around an area to which a source has the ability and right to exclude public access.

There would be a physical barrier (fenceline) that the Liquefaction Facility will control that would limit public access. Therefore, that fenceline identified on the facility site plan (Alaska LNG 2016b) was used as the ambient air quality boundary around the facility. Additionally, there is a need to exclude the public from the immediate area surrounding the trestle and LNG carrier berths during loading/unloading operations for safety reasons including:

- avoidance of collisions with LNG carriers,
- the risk of LNG leak and consequent pool fire, and
- the risk of fire and explosion on board the LNG carriers.

The regulatory process that determines the dimensions of a marine safety and security zone has not been completed. As a proxy, a 500-foot (152-meter) buffer zone was used as an ambient air quality boundary in the air dispersion modeling analysis. Receptors were also excluded in the immediate vicinity (100 feet) of offsite marine vessels. The ambient air boundaries surrounding the on-shore Liquefaction Facility and the LNG carriers and trestle, as well as ambient boundaries around offsite sources, are shown in **Figure 5-3**.

Receptor locations developed in accordance with ADEC modeling guidance (ADEC 2016a) as a Cartesian grid centered on the Liquefaction Facility were spaced as follows:

- 25-meter spacing along the Liquefaction Facility fenceline as well as offsite facility fencelines.
- 25-meter spacing along boundary of the 500-foot exclusion zone around the LNG carriers and trestle.
- 25-meter spacing extending from the Liquefaction Facility fenceline and the 500-ft exclusion zone out to a minimum distance of 200 meters.
- 50-meter spacing extending out to 500 meters from the Liquefaction Facility fenceline, and extending over areas where an overlap in impacts between the facility and offsite sources is possible.
- 100-meter spacing out to 1 kilometer from the Liquefaction Facility fenceline.
- 250-meter spacing out to 2.5 kilometers from the Liquefaction Facility fenceline.
- 500-meter spacing out to 5 kilometers from the Liquefaction Facility fenceline.
- 1,000-meter spacing out to 10 kilometers from the Liquefaction Facility fenceline.
- 2,000-meter spacing out to 20 kilometers from the Liquefaction Facility fenceline.

Additionally, preliminary modeling indicated an area of elevated concentrations due to hilly terrain located 4-5 kilometers (2.5 to 3 miles) north of the facility. Therefore, a small 50-meter spaced receptor grid was placed over each of three hills to ensure the maximum concentrations on the terrain were predicted.

When conducting cumulative modeling, impacts from an offsite source are not included on totals at receptors within that source’s fenceline. Therefore the cumulative modeling was separated into the following analyses:

- The main cumulative modeling analysis determined impacts at receptors along and outside the Liquefaction Facility fenceline and offsite source fencelines, where all facility and offsite sources are modeled. (See **Figure 5-3**).

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- Several separate analyses determined impacts at receptors within an offsite source's fenceline, where that source is excluded from the modeling but the remainder of all facility and offsite sources are included.

The maximum of the impacts determined between the analyses described above was reported as the overall cumulative impact.

Modeling for the Liquefaction Facility alone included all receptors along and outside the facility fenceline, including those receptors within offsite source fencelines. **Figure 5-3** depicts the near-field receptor grid (for cumulative modeling) out to 1 kilometer. **Figure 5-4** depicts the near-field receptor grid out to 20 kilometers.

5.5 ELEVATION DATA

The terrain data to determine receptor and source elevations were obtained from the United States Geological Survey National Elevation Dataset (NED) (<http://ned.usgs.gov>). The highest possible resolution data (1/9th arc second) was used and processed with the AERMAP processor to assign elevations to the receptor locations.

Additionally, the proposed facility was assumed to be graded at an elevation of 38 meters (125 feet) above sea level, which is the approximate average elevation of the receptors along the fenceline (excluding locations along the immediate shore). Therefore, all emission unit stacks and structures at the facility were assigned a base elevation of 38 meters.

5.6 BUILDING DOWNWASH AND STACK HEIGHT

Building structures that obstruct wind flow near emission points may cause stack discharges to become entrained in the turbulent wakes of these structures leading to downwash of the plumes. Wind blowing around a building creates zones of turbulence that are more intense than if the building were absent. These effects generally can cause excessive ground-level pollutant concentrations, from elevated stack discharges. For this reason, building downwash algorithms are considered an integral component of the selected model.

The modeling analysis followed the guidance provided in the USEPA Guidelines for Determination of Good Engineering Practice (GEP) Stack Height (USEPA 1985). The USEPA GEP guidelines specify that the GEP stack height is calculated in the following manner:

$$H_{GEP} = H_B + 1.5L$$

H_B = the height of adjacent or nearby structures

L = the lesser dimension (height or projected width) of the adjacent or nearby structures)

The effects of plume downwash were considered for all emission units. Direction-specific building dimensions were calculated using the current version of the USEPA-approved Building Profile Input Program (BPIPPRM Version 04274). The BPIPPRM program also calculates the Good Engineering Practice (GEP) stack heights for all modeled emission units.

Building dimensions developed for the Liquefaction Facility were input to BPIPPRM where possible. Where heights were not available, single-story building heights containing process equipment or emission units were assigned a height of 8 meters (26 feet, 1.5 times the height of a typical single story building). Modeled source locations were based on the facility site plan.

Dimensions for the LNG carriers were set to those developed for the Corpus Christi Liquefaction project (Cheniere Energy 2013). Dimensions corresponding to a 217,000 cubic meter vessel were used, as that size is the upper limit of the range of ship sizes expected to visit the Marine Terminal. Selecting the largest ship size is conservative as it maximizes potential stack downwash.

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The modeled layout of the proposed Liquefaction Facility is shown in **Figure 5-5** which details the structure locations and heights, as well as the emission unit stack locations and heights that were included in the building downwash analysis.

5.7 NO₂ MODELING APPROACH

The NAAQS and AAAQS for nitrogen oxides (NO_x) are expressed in terms of NO₂. For modeling purposes, additional calculations and modeling approaches are used to determine NO₂ impacts from modeled NO_x emissions. The USEPA Modeling Guideline presents a three-tiered approach that may be applied to modeling 1-hour and annual NO₂ impacts. These three tiers are:

- Tier 1: assume full conversion of NO to NO₂. In other words, it assumes that all NO_x is emitted as NO₂.
- Tier 2: multiply the Tier 1 result by an empirically derived ambient NO₂/NO_x ratio, with 0.80 as the 1-hour national default and 0.75 as the annual national default.
- Tier 3: detailed screening methods may be considered on a case-by-case basis, with the Ozone Limiting Method (OLM) and the Plume Volume Molar Ratio Method (PVMRM) identified as detailed screening techniques.

Preliminary modeling indicated that assuming full conversion of NO_x to NO₂ (Tier 1) was too conservative for this analysis. Therefore, consistent with recent USEPA guidance (USEPA 2014b), Tier 2 was implemented using the Ambient Ratio Method 2 (ARM2).

The ARM2 option applies an ambient ratio to the modeled NO_x concentrations based on a formula derived empirically from ambient measurements of NO₂/NO_x ratios. ARM2 was implemented with default upper and lower limits (of 0.9 and 0.2, respectively) on the ambient ratio applied to the modeled concentration. The lower limit of 0.2 is appropriate for this analysis because an ambient in-stack NO₂/NO_x ratio of 0.2 is representative of in-stack ratios of the sources dominating the impacts. While a few sources may have in-stack ratios above 0.2, those most culpable for the maximum 1-hour NO₂ impacts, such as the Project's LNG carriers, are at 0.2 or below. Furthermore, USEPA guidance recommends that if the total conversion results (Tier 1) from primary source are within 150 – 200 ppbv, that impacts are likely to be appropriately conservative when using ARM2, regardless of the ISR of the primary source (USEPA 2014b). In the current case, the primary source is the Liquefaction Facility. The Tier 1 total 1-hr NO₂ impact due to the Liquefaction Facility is approximately 134 ppbv, thus it is likely that results obtained using ARM2 are appropriately conservative.

ARM2 is currently a non-default BETA AERMOD option that requires case-by-case approval from USEPA. However, USEPA has proposed adoption of this option as a regulatory default option in their recently proposed revisions to the Guideline (USEPA 2015b).

Figure 5-3: Near-Field Receptor Grid and Ambient Air Quality Boundaries out to 1 Kilometer

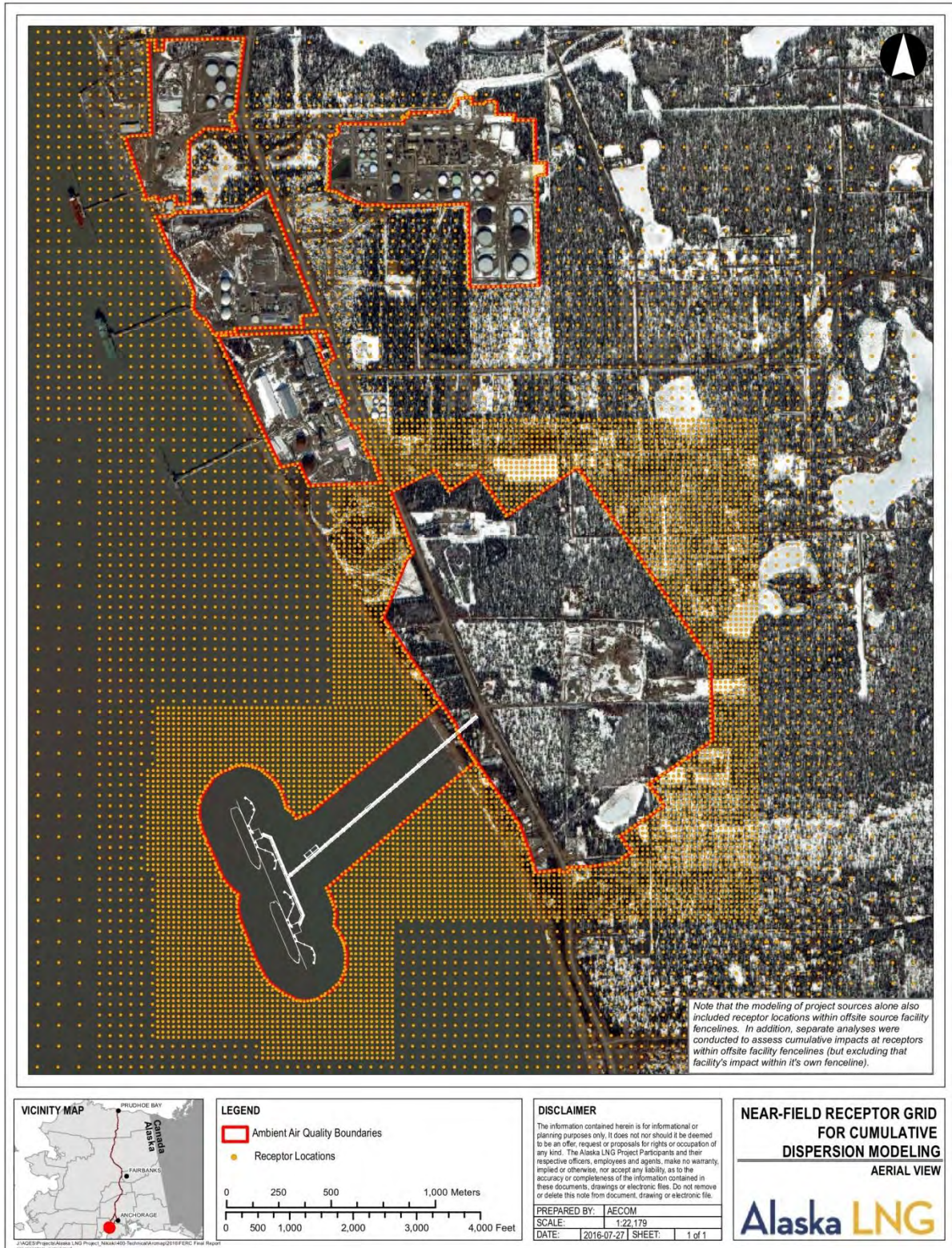


Figure 5-4: Near-Field Receptor Grid out to 20 Kilometers

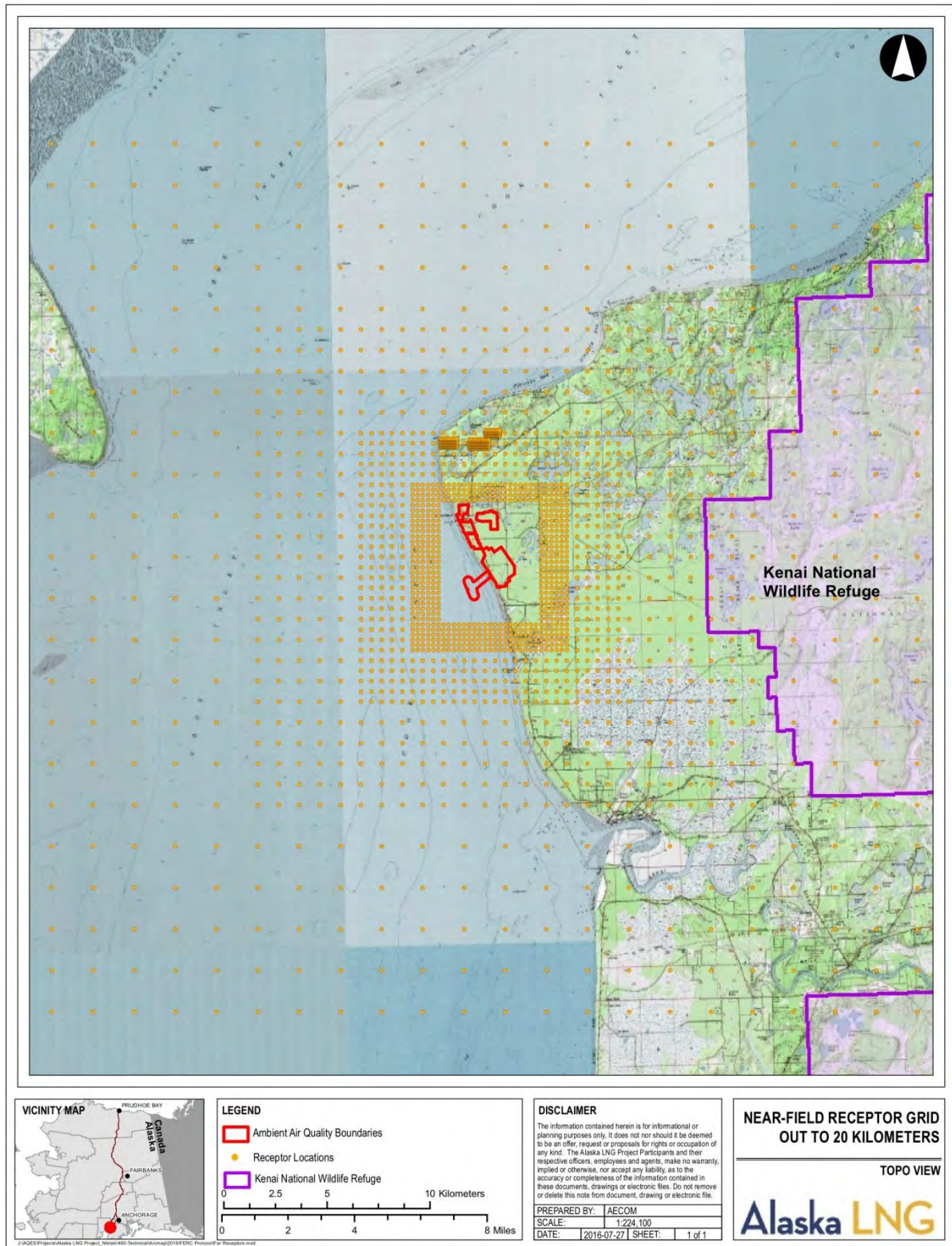
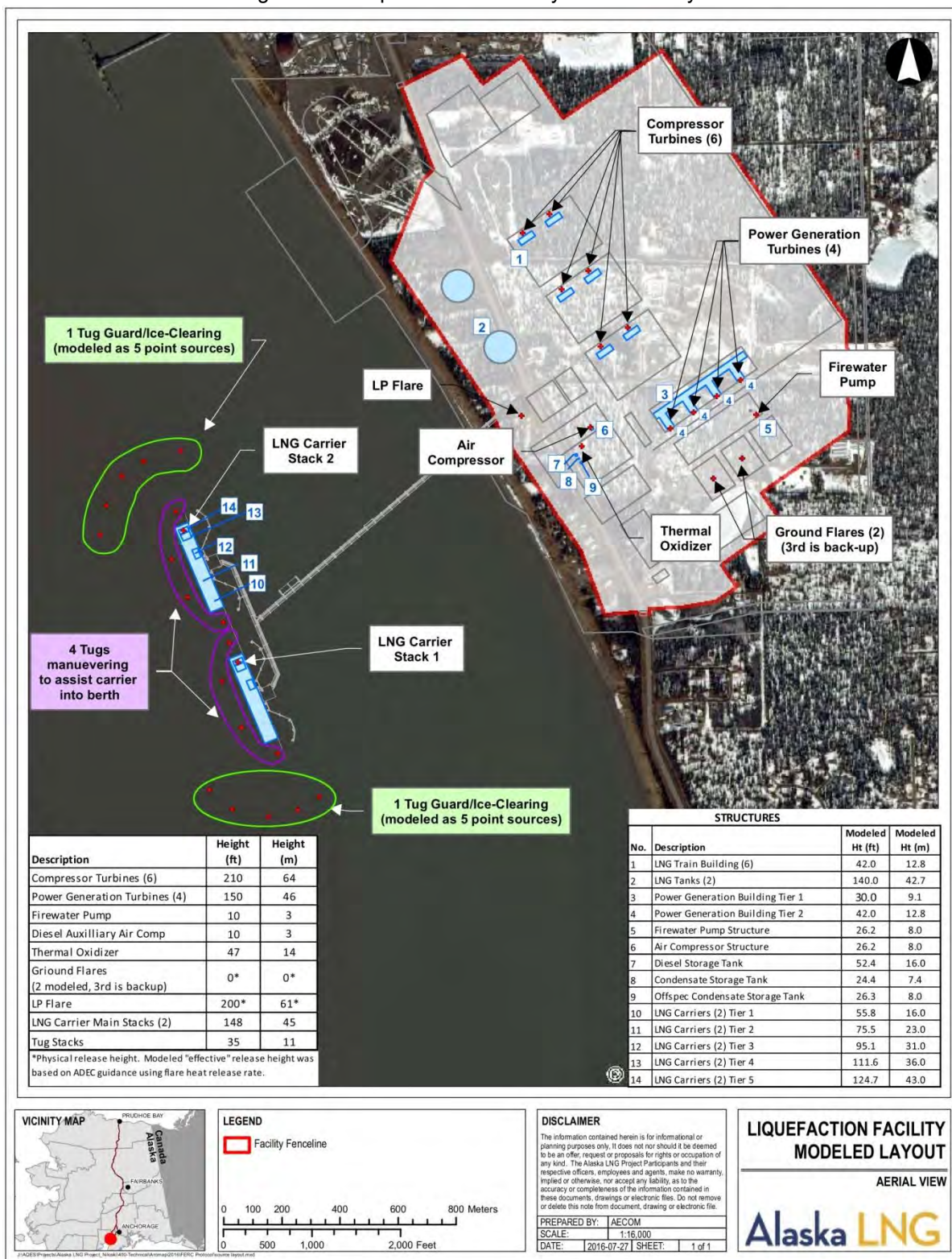


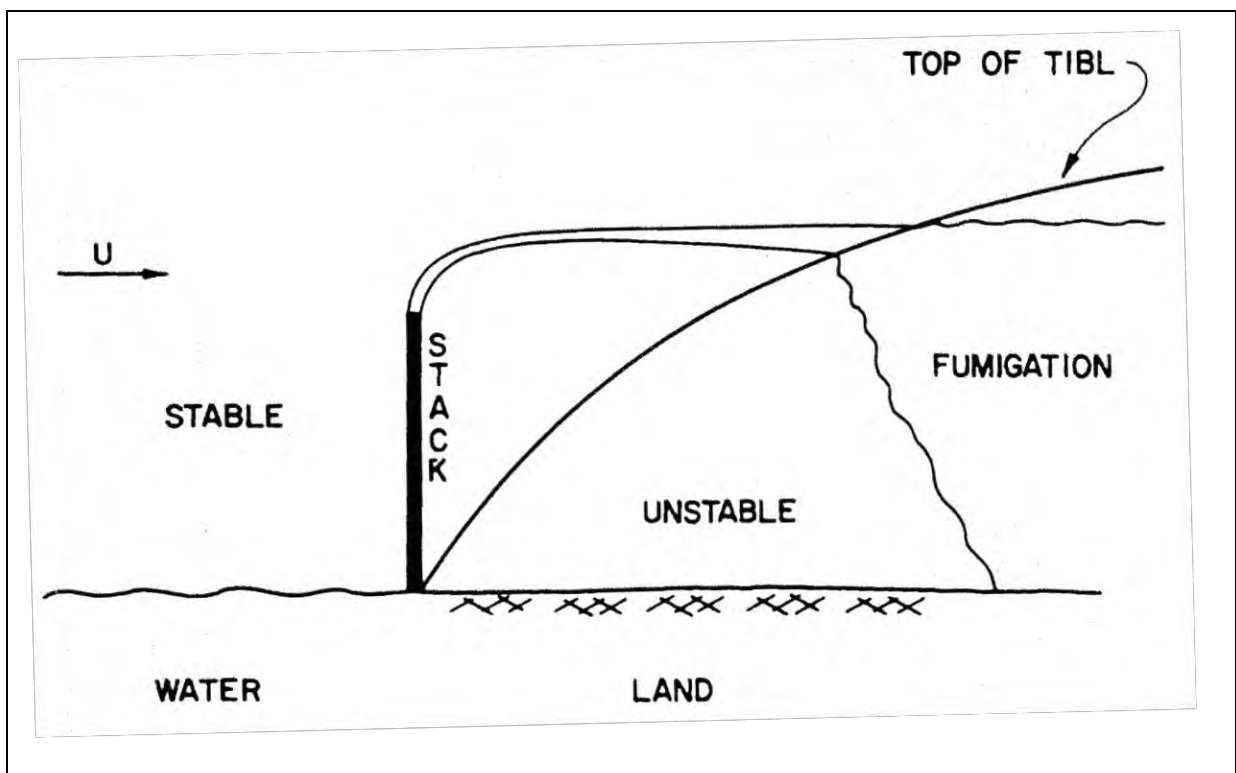
Figure 5-5: Liquefaction Facility Modeled Layout



5.8 SHORELINE FUMIGATION

Shoreline fumigation can occur when a plume is emitted from offshore sources or tall onshore emissions sources, such as a power plant stack, under unique meteorological conditions along a coastal boundary. When a plume is emitted in a stable offshore boundary layer with flow onto the shore, fumigation occurs when the plume impacts an unstable onshore boundary layer, known as the thermal internal boundary layer (TIBL). As shown below in **Figure 5-6**, when the plume in the stable air layer interacts with the TIBL, that layer is mixed to the ground and can result in elevated concentrations of ground-level pollutants from both near-shoreline plumes and other regional sources of emissions.

Figure 5-6: Depiction of Typical Shoreline Fumigation (Stunder et al. 1986)



USEPA's Modeling Guideline advises that air quality modeling analyses should address conditions when fumigation is expected to occur from sources near or just inland of the shoreline. Though impacts from fumigation events should be addressed, most onshore near-field air quality models, including AERMOD, are not equipped to characterize shoreline fumigation events. In rare cases, a conservative screening analysis using AERSCREEN can be used to address shoreline fumigation; otherwise, the Guideline on Air Quality Models cites the Shoreline Dispersion Model (SDM) as a refined means to account for air quality conditions when shoreline fumigation is expected to occur.

The SDM model is a hybrid model that can estimate ground level concentrations for both fumigation and non-fumigation conditions. The SDM model first uses the following criteria to determine whether fumigation events are expected:

- Wind direction at the shoreline sources must be onshore (airflow at an angle of at least 20 degrees).
- Wind speed must be greater than 2 m/sec.

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- Daytime with overland stability class A, B, or C.
- Stable overwater lapse rate (positive potential temperature gradient).

If all of the above criteria are met, the SDM uses the Shoreline Fumigation Model (SFM) to determine concentrations. For the remaining hours when there is no fumigation expected, the SDM uses the MPTER model (multiple point source dispersion algorithm with terrain) to determine concentrations. Note that the MPTER model was selected because it was the USEPA-preferred regulatory model for estimating ground-level concentrations at the time of the SDM model development (USEPA1988).

5.8.1 Meteorological Data

The SDM model requires two sets of meteorological data:

- Surface data – wind speed, wind direction, temperature, stability class, and mixing height.
- Tower data – wind speed within the TIBL, wind speed at stack height, surface sensible heat flux, potential temperature over land, potential temperature over water, and vertical potential temperature gradient over water.

Surface Data

To develop the surface data, USEPA's PCRAMMET program was used to process 2008-2012 data observed at Kenai NWS station with concurrent twice daily mixing height data for Anchorage, AK. For input to PCRAMMET, Kenai surface data were obtained from Trinity Consultants in CD-144 format. Twice daily mixing height data were developed by inputting upper air sounding data and surface temperatures from Anchorage into USEPA's Mixing Height Program (version 98340). Note that the SDM model only uses mixing height values for non-fumigation hours when the MPTER model is invoked. For fumigation hours, the SDM model does not use the mixing height but instead develops a TIBL height based on surface sensible heat flux, potential temperature gradient over water, wind speed, and downwind distance. As described below, the current analysis only used the SDM model for fumigation hours. Therefore, the actual mixing height values input to the model were irrelevant.

Tower Data

The tower data were developed using a combination of surface data from Kenai NWS and buoy data collected at the National Data Buoy Center (NDBC) station located in Nikiski (Station NKTA2). The wind speed within the TIBL was developed for input to SDM by estimating the winds at 60 meters (200 feet) using Kenai surface winds scaled by the power law according to stability category, using wind speed profile exponents used in the USEPA's ISCST3 model (predecessor of AERMOD). Wind speed at the stack height was also calculated in this manner such that the wind speed within the TIBL was set equal to the wind speed at stack height.

Potential temperature is defined as the temperature that would be measured at an air pressure of 1000 millibars (mb). Given that the typical air pressure at Kenai NWS is approximately 1010 mb, the potential temperature is nearly equivalent to the surface temperature measured at Kenai and thus the Kenai surface temperature was used. Surface sensible heat flux at Kenai NWS, as calculated by the AERMET processor, was also used as part of the "tower data" file.

Similar to potential temperature over land, the potential temperature over water was set equal to the air temperature observed over water recorded at the Nikiski buoy for 2008-2012. The vertical potential temperature gradient over water was also developed from the buoy data. First, the difference between the air temperature above the water surface and the temperature of the surface water was determined. This temperature difference was then divided by 3.4 meters, the measurement height of the buoy air temperature sensor. The potential temperature gradient in an isothermal atmosphere is about 10 °C per km or 0.01 °C/m. This gradient, often referred to as the

adiabatic lapse rate, was added to the measured temperature gradient to obtain the potential temperature gradient.

Note that water temperature data were not available for some of the colder months, generally when ice was present. However, fumigation is far more likely to occur during warmer months when the temperature over land easily becomes warmer than the nearby cooler air over water. Therefore, even if data were available for those missing periods it isn't likely the outcome of the modeling analysis would be affected.

Also note that the shallow depth of the water temperature sensor of the Nikiski buoy causes it to occasionally be located out of the water during very low tide events. These periods only occurred occasionally for 1-2 hours at a time and were removed from the dataset. **Table 5-3** indicates that there are valid air and water temperatures for greater than 98% of the period of available data, even after removing those water temperatures affected by low tide.

Table 5-3: Data Capture for Nikiski Buoy Data

Year	Water Temperature Data Availability		% Missing During Period Available	
	Begin (MM/DY)	End (MM/DY)	Air Temperature	Water Temperature
2008	03/09	12/13	0.8%	0.8%
2009	05/01	12/18	0.2%	0.2%
2010	04/06	12/03	2.0%	2.0%
2011	04/20	11/24	1.2%	1.3%
2012	04/23	11/17	0.8%	0.8%

5.8.2 Fumigation Analysis

The shoreline fumigation analysis for the Liquefaction Facility used the SDM model to determine the maximum hourly fumigation concentration, which was then added to cumulative AERMOD modeling results to account for fumigation. Rather than relying solely on SDM, this approach was used because 1) adding the maximum hourly concentration due to fumigation to AERMOD results regardless of averaging period is highly conservative, and 2) this approach primarily relies upon USEPA's preferred model, AERMOD, rather than the decades-old SDM. If this approach was found to be too conservative, then AERMOD was run using hourly fumigation concentrations in a background file to determine the overall impacts.

Note that only fumigation concentrations output by the SDM model were used. Concentrations resulting from non-fumigation hours were not used as the MPTEP model invoked by SDM is no longer a USEPA-approved model.

The procedure for the fumigation analysis is described in detail below.

1. Determine the maximum 1-hour concentration predicted for fumigation hours with the SDM model.

The SDM model was run with all sources associated with the Liquefaction Facility with the exception of the tugs. It is unlikely that tug operations would realistically contribute to any potential shoreline fumigation due to the transient and mobile nature of the tug operations.

Also, because the SDM model is limited to land-based source locations, the LNG carriers were located at the shoreline for the fumigation simulation. This is conservative because realistically, the actual offshore location of the carriers allows for more time for plume rise and dispersion prior to any potential intersection with the TIBL when compared to the modeled shoreline

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location. A higher plume would intersect with the TIBL at a higher point and thus fumigate to the ground farther downwind than a similar but lower plume. Impacts occurring farther downwind are expected to be less than those occurring closer to the source.

2. Add maximum 1-hour fumigation concentrations to cumulative AERMOD modeling results.

As a conservative “first tier” analysis, the maximum 1-hour fumigation concentration found with the SDM model was added to cumulative AERMOD results, regardless of averaging period. For the 1-hour NO₂ NAAQS analysis, annual NO₂ PSD Increment analysis, and 24-hour PM_{2.5} PSD Increment analysis, this proved to be too conservative, thus those analyses were refined using the AERMOD model.

As a refinement to the first tier analysis, an hourly varying background file was used in AERMOD to add the fumigation concentration to cumulative modeling results for Liquefaction Facility and offsite sources. The background file used the SDM maximum 1-hour fumigation concentration for hours where fumigation is expected (based on the above criteria) and a zero for hours where fumigation is not expected.

While not as conservative as the first tier analysis above, this “second tier” analysis still overestimates the contribution from potential fumigation. For every hour that fumigation occurs, this procedure adds the maximum fumigation concentration to every impact predicted within the modeling domain and not just at that location where the maximum fumigation impact is predicted to occur. This will overestimate impacts on the largest part of the modeling domain. Furthermore, combining the impact from fumigating and non-fumigating conditions also leads to overestimation of cumulative impacts because sources culpable for fumigation in the SDM model are also modeled in AERMOD. Thus, there is inherently some “double-counting” of impacts.

The results of the above analyses are incorporated into the summary tables presented in **Section 7.1**.

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6.0 CLASS I AND SENSITIVE CLASS II AREA MODELING METHODOLOGY

This section describes the methodology of modeling the Liquefaction Facility and background sources emissions with the purpose to assess ambient concentration, visibility, and acidic deposition in Class I (Tuxedni National Wildlife Refuge (NWR) and Denali National Park (NP)) and Sensitive Class II areas (Kenai NWR, Chugach National Forest (NF), Lake Clark National Park & Preserve (NPR), Kenai Fjords NP, and Kodiak NWR).

6.1 MODEL SELECTION

Air quality impacts predicted at Class I and sensitive Class II areas for comparison to the NAAQS and PSD increments were determined using the USEPA-approved version of the CALPUFF modeling system (Version 5.8). This modeling system includes the following processors:

- CALMET – Version 5.8 – Level 070623
- CALPUFF – Version 5.8.4 – Level 130731
- POSTUTIL – Version 1.56 – Level 070627
- CALPOST – Version 6.221 – Level 082724

At the time that this analysis was complete, with the exception of CALMET, these were the most current USEPA-approved versions of the CALPUFF modeling system. Since that time USEPA released updated versions of CALPUFF and CALMET. Version 5.8.5 (Level 151214) replaces Version 5.8.4 (Level 130731). The USEPA-approved version of CALPOST remains at Version 6.221 (Level 080724). CALPUFF and CALMET were updated to incorporate minor bug fixes. For this analysis, these new versions will result in negligible differences from those predicted with the previous versions; hence they were not incorporated into this analysis which would delay submittal.

Both the near-field and far-field deposition analyses were performed using the CALPUFF modeling system. While there is accepted FLM guidance for near-field deposition modeling using the AERMOD model, it is considered a conservative screening technique. The CALPUFF modeling system is a more refined method that is an accepted technique following FLAG 2010, particularly when the modeling domain contains receptors both in the near-field and far-field.

Note that because the majority of receptors for the Class I and sensitive Class II areas are beyond 50 kilometers and for consistency with the deposition analysis, CALPUFF was used to determine ambient air quality at both near-field and far-field receptors located in these areas.

The near-field visibility analysis was conducted with the USEPA-approved visibility screening model VISCREEN (Version 13190).

The near-field ambient concentration assessment was conducted with the USEPA-approved dispersion model, AERMOD as described in **Section 5.0**.

6.2 MODEL INPUTS

Point source parameters and emissions rates that were used to model the Liquefaction Facility are provided in **Table 4-3** and **Table 4-4**. Point source parameters and emissions rates used to model Marine Terminal sources are provided in **Table 4-5** and **Table 4-6**. In addition to the above sources, the far-field modeling analysis also included existing sources and reasonably foreseeable development sources. **Table 4-7** lists the data sources used to develop the modeling inputs for these sources.

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For visibility modeling, particulate matter emissions were speciated into filterable (elemental carbon) and condensable (secondary organic aerosol) according to the AP-42 for each source type. Detailed emissions calculations are documented in Appendix A.

All source locations are referenced to Lambert Conformal Conic coordinate system, centered at 59°N, 151°W, with standard latitudes of 30°N and 60°N. Building downwash parameters were used for Liquefaction Facility sources as described in **Section 5.6** and modeled with the PRIME algorithm.

6.3 MODEL OPTIONS

All CALPUFF model options that were used conform to the USEPA guidance (USEPA 2006) or defaults (“MREG = 1” option in CALPUFF). Ammonia-limiting method in POSTUTIL program was used to repartition nitric acid and nitrate on a receptor-by-receptor and hour-by-hour basis to account for over prediction due to overlapping puffs in CALPUFF. It was accomplished by turning on the option “MNITRATE” to 1 and “NH3TYP” to 3.

The CALPOST model options and inputs followed the FLAG 2010 guidance and inputs (USDOJ 2010). Visibility modeling used “MVISBK = 8” and “M8_MODE= 5” options to compute background extinction. The extinction coefficients for the modeled Sensitive Class II areas are not provided in the FLAG 2010 document. Due to the proximity of Tuxedni NWR to these modeled Sensitive Class II areas, Tuxedni extinction coefficients (from FLAG 2010) were used for visibility modeling of these Sensitive Class II areas.

The annual average concentrations, Rayleigh scattering coefficient, and sea salt concentrations were taken from FLAG 2010 Table 6. The monthly relative humidity adjustment factors for large sulfate and nitrate particles were obtained from FLAG Table 7 and for small particles from FLAG Table 8. The sea salt relative humidity adjustment factors were obtained from FLAG Table 9.

6.4 MODELING DOMAIN

The modeling domain is limited by the gridded meteorological input data obtained for use on this project (see **Section 6.7**). However, the modeling domain is 540 km by 650 km, which is large enough to encompass the Liquefaction Facility, background sources, and receptors at Class I and Sensitive Class II areas within 300 kilometers (186 miles) of the Liquefaction Facility. The domain is based on a Lambert Conformal Conic coordinate system centered at 59°N, 151°W, with standard latitudes of 30°N and 60°N and a 2-km grid size. Where possible, the edge of the domain extended at least 50 km from the nearest receptor to ensure the model captures potential puff recirculation effects. The modeling domain is shown in **Figure 6-1**.

The horizontal resolution, geographic projection and datum were based on the CALMET prognostic meteorological data grid. The following vertical layers were used:

0, 20, 40, 65, 120, 200, 400, 700, 1,200, 2,200, and 4,000 meters

6.5 OZONE AND AMMONIA DATA

Representative ozone and ammonia data are required for use in the chemical transformation of primary pollutant emissions. Hourly ozone is used by CALPUFF to account for the oxidation of NO_x and SO₂ emissions to nitric acid and sulfuric acid, respectively. The predicted nitric acid and sulfuric acid are then partitioned in CALPUFF between the gaseous and particulate nitrate and sulfate phases based on the available ammonia, as well as ambient temperature and relative humidity.

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Hourly ozone data for 2002-2004 from Denali National Park were used in CALPUFF. This dataset was developed and approved for use in the Best Achievable Retrofit Technology (BART) regional haze modeling for this area (ADEC 2014). The ozone station location is depicted in **Figure 6-1**.

The ammonia data input to CALPUFF has a direct effect on the amount of visibility degradation predicted by the model. Typically, a smaller ammonia background concentration results in less secondary particle formation from a modeled source's SO₂ and NO_x emissions and would produce less visibility degradation at modeled areas. The Western Regional Air Partnership (WRAP)¹ and USEPA (BART rule²) have acknowledged the limitations of CALPUFF chemistry for predicting wintertime nitrates. This is especially true for the very cold Alaskan winters, in which the temperatures are often well below the 50°F (or higher) that the CALPUFF MESOPUFF-II chemistry is based upon. The independent evaluations³ of just nitrate formation show an over-prediction factor ranging from 2 to 4 for just this issue unless very low ammonia background concentrations are input to CALPUFF. Despite its importance in atmospheric chemistry and CALPUFF model sensitivity to ammonia levels, ammonia is not routinely measured by any national monitoring network.

To determine the appropriate ammonia concentration for input to CALPUFF, a review of available guidance and literature was conducted. The Federal Land Managers' Air Quality Related Values Work Group (FLAG 2010) document suggests using 10 ppbv for grassland, 0.5 ppbv for forests, and 1 ppbv for arid lands, unless better data is available for a specific modeling domain. The "CALMET/CALPUFF Modeling Protocol for BART Exemption Screening Analysis for Class I Areas in the Western United States" (WRAP 2006) recommends a much smaller background NH₃ value of 0.1 ppbv for Alaska (WRAP 2006). This recommendation was used for the WRAP Regional Modeling Center (RMC) BART modeling for sources Alaska as well as for the BART determination modeling for Golden Valley Electric Association (GVEA) Healey Plant⁴.

Table 6-1 summarizes the findings of the literature review, noting measured and modeled ammonia concentrations in the western United States and Alaska. Although the values listed represent many different assumptions (models, resolution, time frame, averaging period) they all indicate a generally low ammonia background value in Alaska with concentrations consistently much lower than 1 ppbv during cold months and higher concentrations during warmer months (note that CALPUFF is not sensitive to ammonia concentrations during warmer temperatures). Ammonia levels are affected by changes in temperature because vegetation acts as a main source of atmospheric ammonia (besides relatively constant source of livestock waste and fertilizers). An analysis of the satellite data over Alaska conducted for this project also found a clear indication of seasonality in measured ammonia levels.

These findings, in conjunction with an understanding of CALPUFF's inherent limitations and conservatisms regarding ammonia and in-transit chemistry, support the use of seasonal rather than annual uniform concentrations of ammonia in the model. As shown in **Table 6-2**, 30 years of normal temperature data collected from the stations in the Kenai area suggests that the growing season starts in May and lasts through October based on temperatures above freezing. The remaining months have freezing temperatures with dormant vegetation providing negligible ammonia. As

¹ See slide # 9 at

http://www.wrapair.org/forums/ssjf/meetings/050907/WRAP_Regional_Modeling_SSJF2.pdf.

² Federal Register, July 6, 2005, Volume 70, pages 39121 and 39123.

³ See Figure 1 and Figure 2

<http://mycommittees.api.org/rasa/amp/CALPUFF%20Projects%20and%20Studies/CALPUFF%20Evaluation%20with%20SWWYTAF,%202009,%20Kharamchandani%20et%20al.pdf>

⁴ See page 30

<https://dec.alaska.gov/air/ap/docs/GVEA%20BART%20Final%20Determination%20Report%202-5-10.pdf>

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6.6 VISIBILITY MODELING APPROACH

6.6.1 Near-field Analysis

The near-field plume visibility analysis was conducted using USEPA's VISCREEN model to evaluate the extent of visibility of plumes associated with the Liquefaction Facility in Kenai NWR which is the only Class I or Class II area close enough to be reasonably modeled with a near-field model. VISCREEN is a screening-level plume visibility model recommended in USEPA's Workbook for Plume Visual Impact Screening and Analysis (the Visibility Workbook, USEPA 1992). This model simulates the dispersion and optical characteristics of an elevated emission source plume. It incorporates the straight-line Gaussian dispersion of primary particulate as well as the transformation of primary pollutants (NO_x). It then computes the scattering of direct sunlight due to air-borne pollutants. For a given time of day, wind speed, atmospheric stability, background visual range, and ozone concentration, the model computes light intensity at various visible wavelengths for lines-of-sight through the plume centerline. By comparing the light intensity reaching an observer both with and without the source present, the model computes visibility parameters that can be used to gauge whether or not a plume might be visible against a background sky or terrain.

Inputs which are required by VISCREEN include:

- Emission rates of NO_x and primary particulate (elemental carbon and primary sulfate are optional emission rates),
- Observer distance from source,
- Meteorological conditions (wind speed and atmospheric stability),
- Background visual range, and
- Background ozone concentration.

The two visibility parameters that VISCREEN estimates are specified in the Visibility Workbook and include:

- Plume contrast (C_p) - a measure of the fractional reduction or increase in light intensity at the $0.55 \mu\text{m}$ wave length due to the presence of a plume. This (green) wave length is used because it is at the center of the visible spectrum. According to the Workbook, plume contrast values exceeding 0.05 in absolute value should be used as a screening criterion, inferring that a 5% change in intensity is likely to be noticed by a casual observer.
- Plume perceptibility parameter (ΔE) - an integral measure that incorporates differences in light intensity over all visible wavelengths incorporating human perception. ΔE evaluates the degree to which a plume can be seen either against a sky or terrain background. The Visibility Workbook establishes a ΔE threshold of 2.0 to indicate the presence of a visible plume against a background sky or terrain.

Observer locations chosen for the VISCREEN analysis included the closest Class II sensitive area: Kenai NWR (the most conservative observer location as suggested by the Visibility Workbook) and Skilak Lake (a popular visitor destination within the refuge). Kenai NWR is located approximately 10 kilometers (6 miles) from the Liquefaction Facility and Skilak Lake is located approximately 52 kilometers (32 miles) from the Facility. Both were assessed using a Level II assessment methodology (as described the Workbook). Unless otherwise mentioned, default VISCREEN settings were utilized.

According to FLAG (USDOI 2010), VISCREEN is usually applied for lines of sight that are within 50 kilometers of a source. While a small section of the northeast border of Lake Clark National Park is approximately 50 kilometers from the Liquefaction Facility, that portion of the part of the park is not frequently visited and does not likely contain scenic vistas, and by far the largest majority of the park lies well beyond 50 kilometers. Furthermore, 50 kilometers is at the extreme limit of near-field

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model applicability. All of these issues should be considered together when decided to use a near-field or far-field model to estimate visibility impacts. Following careful consideration, a near-field visibility analysis was not performed at Lake Clark National Park. Instead, a regional haze assessment within Lake Clark National Park was performed using CALPUFF and is described below in **Section 6.6.2**.

The USEPA Visibility Workbook indicates that the highest modeled plume visibility impairment is associated with plume-observer geometry where the wind vector carries the plume centerline 11.25° on either side of the line between the plant and the observer. Thus, one wind vector to left and one to the right of the observer location were simulated. Following the methods described in the Visibility Workbook, the wind speed and atmospheric stability class for the 22.5° wind direction sector for each observer that corresponds to the one percentile worst-case probability will be applied. Wind speed and stability class categories and frequencies were based on the same meteorological data set used for the near-field modeling analyses described in Section 5: 2008-2012 meteorological data from the nearby Kenai NWS station.

Background visual range was determined by averaging the 12 months of average monthly visual range values measured in nearby Tuxedni NWR. This information was found in Table 10 of FLAG 2010.

Emission rates used as inputs for each source included primary NO_x, primary particulate matter, and primary elemental carbon. Note that VISCREEN assumes that 10% of NO_x emissions are initially converted to NO₂, either within the source stack or within the first kilometer of plume transport. In addition, the default VISCREEN ozone background value of 40 ppbv was assumed and is consistent with measurements collected at Denali National Park and used for the long-range assessment with CALPUFF and the near-field NO₂ chemical transformation in AERMOD.

There would be several emission source types at the Liquefaction facility, and many would have different stack parameter characteristics. Some sources would also be large distances apart. For a VISCREEN analysis, it is reasonable to assume that the plumes from many of these sources would not combine into a single plume. Thus, an assessment of which plumes would and would not likely combine was performed. Stack velocities, heights, temperatures and distances were considered in this analysis. A total of 5 separate plumes were conservatively identified. The sources that were combined into each of these plumes are shown in **Table 6-4** with justifications. A specific VISCREEN analysis was performed on each of these plumes to obtain more representative visibility degradation estimations at the observer locations.

Note that only emission rates associated with the pilot/purge operations were modeled in the near-field visibility analysis. Maximum flaring emission rates (which may occur during upset and startup scenarios) associated with the flares were not modeled. Maximum flaring scenarios are expected to be extremely rare and short lived (occurring less than an hour at a time). The probability that these very short-lived maximum flaring events would coincide with the stability classes, wind directions, worst case solar/scattering angles necessary for visibility degradation is very low. In addition, VISCREEN does not consider the extreme dispersion and thermal buoyancy from plumes associated with maximum flaring events. For these reasons, the inclusion of maximum flaring emissions in a VISCREEN analysis would create predicted impacts that are not representative of reasonable foreseeable operations associated with normal operations of the facility.

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Table 6-4: Combined Plume Emission Sources

VISCREEN Analysis	Source Emissions Included in Plume	Justification for Combining Sources
Compressor Turbines	6 Compressor Turbine	Identical source types. Distances apart range from approximately 0.1 to 0.5 km
Power Generator	4 Power Generators + Firewater Pump + Aux Compressor	The Power Generators are located in the same general vicinity of each other. The Firewater Pump and Aux Compressors are also nearby and have stack parameters which suggest potential for combining with Power Generator plumes.
LP Flare	2 LP Flares + Thermal Oxidizer	The two LP flares are nearby each other. The Thermal Oxidizer is also conservatively included with the LP Flares as it is nearby source
Wet/Dry Flare	2 Wet Flares + 2 Dry Flares	All four of these flares are nearby each other and have similar stack parameters
Marine Sources	North Carrier + South Carrier + Support Tugs	Though exact locations of these sources is unknown, they were conservatively combined into a single plume

6.6.2 Far-field Analysis

As noted in **Section 6.5** above, CALPUFF uses measurements of background ammonia concentrations to estimate secondary particulate formation which contributes to the amount of regional haze and visibility degradation predicted by the model. CALPUFF simulates each modeled source individually; thus, the background ammonia concentration is assumed by the model to be fully available to react with emissions from each source. This can lead to the model overestimating secondary particulate formation and regional haze impacts because, in reality, the total emissions from the combination of emission units compete for the available ammonia. Therefore actual secondary particulate formation would be less due to less background ammonia availability. Despite the inherent conservatism in the model, far-field cumulative regional haze impacts were determined by conventional utilization of CALPUFF.

Regional haze impacts due to the Liquefaction Facility were refined by subtracting the offsite regional haze impact from the cumulative regional haze impact, as shown below. This was accomplished by conventional utilization of CALPUFF for the cumulative and existing source groups noted below and post-processing using the POSTUTIL program.

This refined method better accounts for the fact that the available background ammonia is partially consumed by the background emission source inventory.

Project Regional Haze Impact (Liquefaction Facility Sources Only)	=	Cumulative Regional Haze Impact (Offsite Sources + Liquefaction Facility Sources)	-	Background Sources Regional Haze Impact (Offsite Sources Only)

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6.7 METEOROLOGICAL DATA

6.7.1 Prognostic Meteorological Data

The most recent available prognostic meteorological data that exists for the modeling domain is the three-year (2002-2004) Fifth Generation Penn State/NCAR Mesoscale Model (MM5) dataset developed for the Alaska BART Coalition and was used as the gridded, domain-wide prognostic meteorological dataset. This dataset was developed and approved and used in the BART regional haze modeling for this area (ADEC 2014).

The model performance evaluation for the MM5 dataset showed that the wind field depicted within the grid met the specifications for bias and accuracy and was confirmed for use in the CALPUFF modeling (Geomatrix 2007).

6.7.2 CALMET

The MM5 meteorological data was processed using CALMET to develop a meteorological wind field. The performance evaluation of the processed dataset was acceptable to regulatory agencies for BART modeling and therefore was used by the Alaska BART Coalition for Cook Inlet CALPUFF modeling (ADEC 2014). The CALMET/CALPUFF modeling domain is shown by the blue line in **Figure 6-1**.

6.8 RECEPTORS

Receptor locations and their elevations for Tuxedni and Denali were obtained from the National Park Service databases (<http://www.nature.nps.gov/air/maps/receptors/download/ClassIData.zip>).

Receptor placement for Sensitive Class II areas was designed similar to the Denali receptors spacing, with receptors placed every 6 kilometers (3.7 miles) vertically and every 3 kilometers (2 miles) horizontally. Receptors beyond 300 kilometers of the Liquefaction Facility were not modeled since they are beyond the accepted regulatory limit of the model.

Note that the CALMET domain does not extend all the way to the Kodiak NWR, a Sensitive Class II area. Therefore, a surrogate data point to represent Kodiak NWR impacts was placed at the Barren Islands. Also note that receptors shown at the Kenai NWR are located less than 50 km from the Liquefaction Facility.

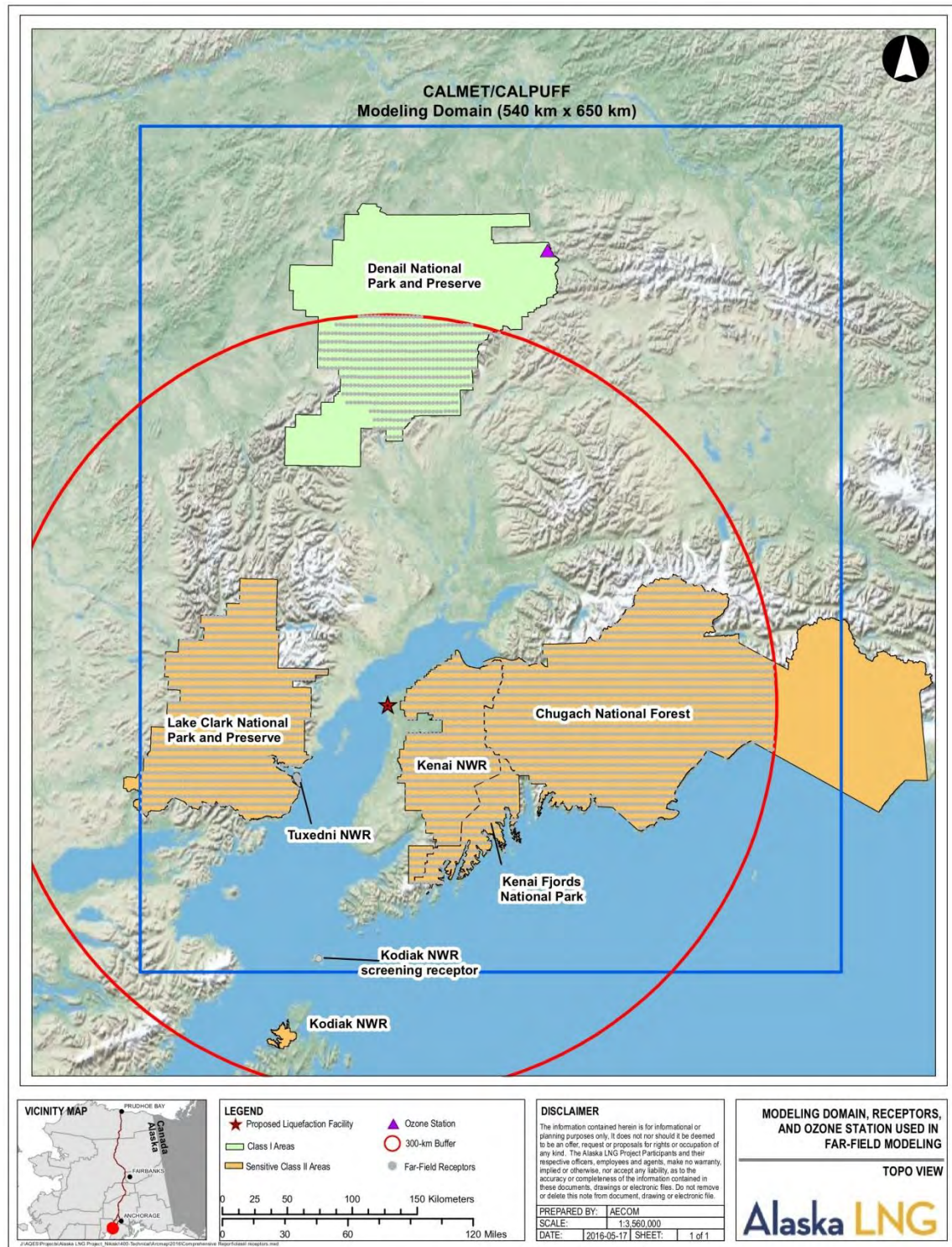
6.9 ELEVATION DATA

The terrain data was extracted from the provided CALMET geo.dat file to assign elevations to the Sensitive Class II receptors using Lakes Environmental CALPUFF View program (available at <https://www.weblakes.com/products/calpuff/>).

6.10 NO₂ MODELING APPROACH

Section 5.7 discusses the three-tiered approach that may be applied to modeling 1-hour and annual NO₂ impacts. Preliminary modeling indicated that assuming full conversion of NO to NO₂ (Tier 1) was too conservative for the Class I and Sensitive Class II Area modeling analysis. Therefore, consistent with recent USEPA guidance (USEPA 2014b), Tier 2 (ARM) was implemented whereby Tier 1 results were multiplied by the default 1-hour and annual NO₂/NO_x ratios of 0.80 and 0.75, respectively.

Figure 6-1: Far-Field Modeling Domain and Receptors



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7.0 MODELING RESULTS

The results of the ambient air quality modeling analyses for the Liquefaction Facility are presented in this Section. Both near-field and Class I and Sensitive Class II area analyses are discussed below. The analyses were conducted according to the technical approaches, source emission rates, and stack parameters presented in **Sections 4, 5, and 6**. Electronic input and output files for all model runs used to develop the results in the tables that follow are transmitted digitally with this report (Doc. No. USAL-P1-SRZZZ-00-000001-001).

7.1 NEAR-FIELD DISPERSION MODEL IMPACTS

This section presents AERMOD results for modeled receptors within approximately 50 kilometers of the Liquefaction Facility. Visibility impacts for near-field sensitive Class II areas are presented in **Section 7.2.4**.

7.1.1 Criteria Pollutant Project Only Impacts

Model-predicted concentrations resulting from normal operations at the Liquefaction Facility alone (no offsite sources) are compared to the NAAQS and AAAQS in Table 7-1 and compared to PSD Class II increments in Table 7-2. These model results are provided for information purposes only since it is more appropriate to compare cumulative impacts to these criteria. All model-predicted impacts are below the applicable standards and increments listed in **Section 2.0**.

7.1.2 Criteria Pollutant Cumulative Impacts

Cumulative model-predicted concentrations from the Liquefaction Facility, existing and proposed offsite sources, and other non-modeled sources (represented by ambient background concentrations) are compared to the NAAQS and AAAQS in Table 7-3. Cumulative model-predicted concentrations are also compared to PSD Class II increments in Table 7-4. While all model-predicted impacts are below the applicable standards and increments listed in **Section 2.0**, it is highly conservative to add the maximum 1-hour fumigation impacts to all cumulative AERMOD impacts, regardless of averaging period. Realistically, any potential impacts due to fumigation would be far less, particularly for 24-hour and annual averaging periods.

Note that lead and ammonia emissions are either negligible or not emitted at all from the Liquefaction Facility; therefore, they were not addressed as part of the dispersion modeling analysis.

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Table 7-1: Liquefaction Facility-Only NAAQS/AAQS Air Quality Compliance Analysis – Normal Operations

Air Pollutant	Averaging Period	AERMOD-Predicted Concentration (µg/m ³)	Ambient Background Concentration (µg/m ³)	Total Concentration (µg/m ³)	NAAQS (µg/m ³)	AAQS (µg/m ³)
Sulfur Dioxide	1-Hour ^a	57.5	5.0	62.5	196	196
	3-Hour ^b	39.6	5.0	44.6	1,300	1,300
	24-Hour ^b	17.1	2.4	19.5	NA	365
	Annual ^d	0.11	0.0	0.11	NA	80
Carbon Monoxide	1-Hour ^b	2,721	1,145	3,866	40,000	40,000
	8-Hour ^b	1,071	1,145	2,216	10,000	10,000
Nitrogen Dioxide	1-Hour ^c	140.1	32.3	172.4	188	188
	Annual ^d	8.4	2.60	11.0	100	100
Particulate Matter less than 10 Microns	24-Hour ^f	5.1	40	45.1	150	150
Particulate Matter less than 2.5 Microns	24-Hour ^e	3.6	12	15.6	35	35
	Annual ^g	0.38	3.70	4.1	12	12

Abbreviations:

NA = not applicable

µg/m³ = micrograms per cubic meter

Notes:

^a Value reported is the 99th percentile of the annual distribution of daily maximum values averaged over the 5-year period.

^b Value reported is the highest, second highest concentration of the values determined for each of the 5 modeled years.

^c Value reported is the 98th percentile of the annual distribution of daily maximum values averaged over the 5-year period.

^d Value reported is the maximum annual average concentration for the 5-year period.

^e Value reported is the 98th percentile averaged over the 5-year period.

^f Value reported is the highest, 6th highest concentration over the 5-year period.

^g Value reported is the annual mean concentration, averaged over the 5-year period.

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Table 7-2: Comparison of Liquefaction Facility-Only Model-Predicted Concentrations to Increment Thresholds – Normal Operations

Air Pollutant	Averaging Period	AERMOD-Predicted Concentration (µg/m ³)	Class II Increments (µg/m ³)
Sulfur Dioxide	1-Hour ^a	NA	NA
	3-Hour ^b	39.6	512
	24-Hour ^b	17.1	91
	Annual ^c	0.11	20
Carbon Monoxide	1-Hour ^a	NA	NA
	8-Hour ^a	NA	NA
Nitrogen Dioxide	1-Hour ^a	NA	NA
	Annual ^c	8.4	25
Particulate Matter less than 10 Microns	24-Hour ^b	5.4	30
	Annual ^c	0.43	17
Particulate Matter less than 2.5 Microns	24-Hour ^b	4.8	9
	Annual ^c	0.43	4

Abbreviations:

NA = not applicable

µg/m³ = micrograms per cubic meter

Notes:

^a Neither USEPA nor ADEC have established increment thresholds for 1-hr NO₂, 1-hr SO₂, 1-hr CO, or 8-hr CO.

^b Value reported is the maximum of the highest-second-high values from each of the five modeled years.

^c Value reported is the maximum annual average concentration for the 5-year period.

Table 7-3: Cumulative NAAQS/AAQS Air Quality Compliance Analysis – Normal Operations

Air Pollutant	Averaging Period	AERMOD-Predicted Concentration ($\mu\text{g}/\text{m}^3$)	Maximum 1-Hour Fumigation Concentration ($\mu\text{g}/\text{m}^3$)	Ambient Background Concentration ($\mu\text{g}/\text{m}^3$)	Total Concentration ($\mu\text{g}/\text{m}^3$)	NAAQS ($\mu\text{g}/\text{m}^3$)	AAQS ($\mu\text{g}/\text{m}^3$)
Sulfur Dioxide	1-Hour ^a	63.4	5.7	5.0	74.1	196	196
	3-Hour ^b	50.6	5.7	5.0	61.3	1,300	1,300
	24-Hour ^b	32.0	5.7	2.4	40.1	NA	365
	Annual ^d	0.6	5.7	0.0	6.3	NA	80
Carbon Monoxide	1-Hour ^b	2,721	78.3	1,145	3,945	40,000	40,000
	8-Hour ^b	1,071	78.3	1,145	2,294	10,000	10,000
Nitrogen Dioxide	1-Hour ^c	149.5	Included ^h	32.3	181.8	188	188
	Annual ^d	20.4	34.1	2.60	57.1	100	100
Particulate Matter less than 10 Microns	24-Hour ^f	23.9	5.0	40	68.9	150	150
Particulate Matter less than 2.5 Microns	24-Hour ^e	6.4	5.0	12	23.4	35	35
	Annual ^g	2.8	5.0	3.7	11.4	12	12

Abbreviations:

NA = not applicable

 $\mu\text{g}/\text{m}^3$ = micrograms per cubic meter

Notes:

^a Value reported is the 99th percentile of the annual distribution of daily maximum values averaged over the 5-year period.

^b Value reported is the highest, second highest concentration of the values determined for each of the 5 modeled years.

^c Value reported is the 98th percentile of the annual distribution of daily maximum values averaged over the 5-year period.

^d Value reported is the maximum annual average concentration for the 5-year period.

^e Value reported is the 98th percentile averaged over the 5-year period.

^f Value reported is the highest, 6th highest concentration over the 5-year period.

^g Value reported is the annual mean concentration, averaged over the 5-year period.

^h Hourly fumigation concentration was modeled in AERMOD through use of background concentration file. Thus, the resulting AERMOD concentration includes fumigation.

Table 7-4: Comparison of Cumulative Model-Predicted Concentrations to Increment Thresholds – Normal Operations

Air Pollutant	Averaging Period	AERMOD-Predicted Concentration ($\mu\text{g}/\text{m}^3$)	Maximum 1-Hour Fumigation Concentration ($\mu\text{g}/\text{m}^3$)	Total Concentration ($\mu\text{g}/\text{m}^3$)	Class II Increments ($\mu\text{g}/\text{m}^3$)
Sulfur Dioxide	1-Hour ^a	NA	NA	NA	NA
	3-Hour ^b	39.6	5.7	45.4	512
	24-Hour ^b	17.5	5.7	23.3	91
	Annual ^c	0.6	4.9	5.5	20
Carbon Monoxide	1-Hour ^a	NA	NA	NA	NA
	8-Hour ^a	NA	NA	NA	NA
Nitrogen Dioxide	1-Hour ^a	NA	NA	NA	NA
	Annual ^c	12.5	Included ^d	12.5	25
Particulate Matter less than 10 Microns	24-Hour ^b	24.7	5.0	29.7	30
	Annual ^c	2.7	5.0	7.7	17
Particulate Matter less than 2.5 Microns	24-Hour ^b	8.7	Included ^d	8.7	9
	Annual ^c	1.3	Included ^d	1.3	4

Abbreviations:

NA = not applicable

 $\mu\text{g}/\text{m}^3$ = micrograms per cubic meter

Notes:

^a Neither USEPA nor ADEC have established increment thresholds for 1-hr NO₂, 1-hr SO₂, 1-hr CO, or 8-hr CO.

^b Value reported is the maximum of the highest-second-high values from each of the five modeled years.

^c Value reported is the maximum annual average concentration for the 5-year period.

^d Hourly fumigation concentration was modeled in AERMOD through use of background concentration file. Thus, the resulting AERMOD concentration includes fumigation.

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7.2 CLASS I AND SENSITIVE CLASS II MODEL-PREDICTED IMPACTS

This section presents results for modeled receptors within selected Class I and Sensitive Class II areas.

7.2.1 Criteria Pollutant Project Only Impacts

Modeled impacts resulting from normal operations for the Liquefaction Facility are compared to applicable standards discussed in **Section 2.0**. Model-predicted concentrations from the Liquefaction Facility only are compared to the NAAQS and AAAQS for each of the selected Class I and Sensitive Class II areas in **Table 7-5** through **Table 7-10**. Model-predicted concentrations from the Liquefaction Facility alone are compared to PSD increment in **Table 7-11** through **Table 7-16**. These model results are provided for information purposes only since it is more appropriate to compare cumulative impacts to these criteria. All model-predicted impacts due to the Liquefaction Facility alone are well below all standards and increments at all modeled Class I and Sensitive Class II areas.

7.2.2 Criteria Pollutant Cumulative Impacts

Cumulative CALPUFF-predicted concentrations from the Liquefaction Facility, existing offsite sources, RFD sources, and other non-modeled sources (represented by ambient background concentrations) are compared to the NAAQS and AAAQS for each far field Class I and Sensitive Class II area in **Table 7-17** through **Table 7-22**. The results indicate that the cumulative air quality impacts, combined with representative background air quality data, are well below the NAAQS and AAAQS at all areas of concern.

Cumulative modeling was also performed for increment-consuming sources only for comparison to PSD Class I and Class II increments. **Table 7-23** through **Table 7-28** present the results, which indicate impacts are less than the PSD increment at all areas of concern.

7.2.3 Secondary PM_{2.5} and PM₁₀ Formation

CALPUFF simulates simple, in-transit transformation of SO₂ emissions to ammonia sulfate and NO_x emissions to ammonium nitrate. PM_{2.5} and PM₁₀ impacts due to Liquefaction Facility sources were calculated using IWAQM guidance and the POSTUTIL processor to include both direct PM impacts along with the modeled ammonia sulfate and ammonium nitrate concentrations. These total PM concentrations are included in the PM_{2.5} and PM₁₀ concentrations in the NAAQS and PSD increment results tables.

7.2.4 AQRV Visibility Assessment

This section describes the results of the AQRV visibility analysis. As suggested by FLAG, two assessments were performed:

- A near-field assessment to determine the near-field impact of non-collocated plumes as compared to a viewing background, and
- A distance/multi-source (far-field) assessment to determine how the general appearance of the overall scene in the region would be affected.

7.2.4.1 Near-field Analysis

Plume visibility at Kenai NWR, which is the only Class I or Class II Area located within 50 kilometers of the Liquefaction Facility, was assessed with the VISCREEN model, as described in **Section 6.6.1**. The plume visibility results of plume perceptibility (ΔE) and plume contrast (C_p) against both a sky and terrain background for each source/observer location combination are shown **Table 7-29** and **Table 7-30**.

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As can be seen, all Cp and ΔE screening criteria were met by large margins for all plumes except for the combined plume associated with the compressor turbines. For the turbines, ΔE and Cp slightly above screening levels were noted at the Closest Park Boundary when viewing both a Sky and Terrain Background. ΔE was also slightly above screening levels at Skilak Lake when viewing a Terrain Background. The highest ΔE occurred at the Closest Park Boundary when viewing a Terrain Background.

While a few results were not less than the Class I screening levels, VISCREEN is by nature a conservative screening model. Results shown are for absolute worst case scattering angles (10 and 140 degrees) based on sun position, and therefore, will only occur for certain portions of year and day, depending on season. The Cp and ΔE terrain background calculations are also based on the assumption that the terrain object being viewed is black. This is also likely conservative considering much of the terrain in reality will be colorful or white.

Finally, it is important to consider that the modeled compressor turbines plume consisted of emissions from six separate turbines. Each of these turbines is separated by a distance of 0.1 to 0.5 kilometer of each other, so instances where these separated turbine plumes would potentially combine into a single plume as modeled are likely rare. ΔE and Cp criteria would be met for all locations and viewing backgrounds if one assumes no more than two of the turbine plumes would ever realistically combine.

7.2.4.2 Far-field Analysis

As shown in **Table 7-31**, predicted visibility impacts (reported as the 8th highest percent change in light extinction) from the Liquefaction Facility alone are below the 5% threshold at nearly all Class I and Sensitive Class II areas. With some additional modeling refinements, it would be below thresholds at all areas of concern, thus the visibility impacts are below de minimis thresholds. The modeled change in light extinction at Lake Clark is 5.1% and 5.3% for 2003 and 2004, respectively; these results are conservative and could be refined as described below:

- A background ammonia value of 1 ppbv was conservatively selected for the growing season. This value is considerably higher than the 0.1 ppbv used for historical BART modeling in Alaska. The actual background ammonia value is likely somewhere in between 0.1 and 1 ppbv, which would reduce visibility impacts, potentially reducing the impact at Lake Clark to below the 5% de minimis threshold.
- Refinement of the conservative assumptions included in the Liquefaction Facility simulation would also lead to lower visibility impacts and likely reduce the impact at Lake Clark NP to below 5%. Refinements could include modeling a more realistic normal operating scenario that does not include operations such as maximum relief flaring combined with all other sources operating normally.

As shown in **Table 7-32**, the cumulative change in light extinction exceeds the 10% threshold at all far-field areas. Because cumulative impacts show potential issues where the source-only impacts do not, it is evident that the elevated impacts are attributable to offsite sources.

Note that existing visibility extinction measurements reported through the IMPROVE program at Tuxedni NWR and Denali NP are much lower than cumulative model-predicted impacts at these locations. Thus, it is clear the model is over-predicting cumulative impacts and likely over-predicting Liquefaction Facility-only impacts as well, which are already essentially below 5%. Note that the CALPUFF model includes the conservative assumption of a steady background visibility condition that only slightly varies monthly. In reality, there is daily variation of measured aerosols, which is not accounted for in the model. If the model were able to be refined to account for daily visibility variation it is likely that model-predicted visibility impacts would be lower.

7.2.5 AQRV Deposition Modeling Results

As shown in **Table 7-33**, the sulfur deposition flux from the Liquefaction Facility alone is slightly above the DAT at Tuxedni NWR, Kenai NWR, and Lake Clark NP. The onshore sources located at

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the Liquefaction Facility most culpable for these impacts. It is worth noting that the upper limit of pipeline quality natural gas sulfur content (16 ppmv) was assumed in the calculations of emissions for these sources and that the actual fuel sulfur content will likely be much lower (by as much as half), which would mitigate sulfur deposition impacts.

Table 7-34 shows that the nitrogen deposition flux from the Liquefaction Facility also exceeds the DAT at Tuxedni NWR, Kenai NWR, Lake Clark NP, as well as Denali NP. However, it is believed that refinements to the conservative assumptions included in the normal operations scenario for the facility would reduce deposition impacts to below the DAT for all areas. Refinements could include modeling a more realistic normal operating scenario which does not include operations such as maximum relief flaring, and/or modeling the turbines at a more realistic load instead of the conservative 100% that was assumed. These refinements would also reduce the sulfur deposition impacts.

Cumulative deposition modeling results are shown in **Table 7-35** and **Table 7-36** and indicate that modeled nitrogen and sulfur deposition fluxes all within the cumulative DAT

Note that DATs for both the Liquefaction Facility-only and cumulative deposition assessments are screening thresholds developed to be conservatively protective of all Class I areas regardless of location-specific natural background and buffering capacity. If park-specific studies were available, there may be an opportunity to refine and increase the acceptable thresholds. For example, because the natural background is directly related to the calculation of the DATs (shown in **Section 2.3.3**), an elevated natural background at a particular location would result in a higher DAT.

7.3 MODELING CONCLUSIONS

- The following are conclusions based on the results discussed above for near-field receptors and receptors at the modeled Class I and Sensitive Class II areas. Considering the following conservative assumptions, the modeling results indicate there is no concern the Liquefaction Facility would cause adverse air, deposition, or visibility impacts at near-field, Class I, or Sensitive Class II areas:
 - o All equipment located at the Liquefaction Facility is assumed to operate concurrently, even intermittently used emergency equipment.
 - o Short-term turbine emissions are based on worst-case, rather than average, ambient temperatures. Average temperature would result in lower emissions.
 - o The turbines are assumed to operate at 100% load, even though it is more likely they will operate at near 90% load, which would result in lower emissions.
 - o 500 hours per year of maximum relief flaring is included in the modeling demonstration in addition to continuous pilot purge and all other equipment operating. While maximum relief flaring is inevitable, it is unlikely to occur as much as 500 hours per year and with all other equipment operating.
 - o The modeled marine scenario assumes that two carriers will call within a few hours of one another, with both docked concurrently for a period of time, though it is far more likely that only one carrier would call at any time.
- Despite the aforementioned conservative assumptions:
 - o At near-field locations, model-predicted impacts are below all air quality standards and increments.
 - o At far-field locations, model-predicted impacts are below all air quality standards and increments at all Class I and Sensitive Class II areas.
- While some results of the near-field visibility assessment were above Class I screening levels, they are likely attributable to:

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- o The worst-case meteorological conditions included in the screening-level VISCREEN model, which are infrequent and unlikely to occur simultaneously with the wind direction required for an observer to notice the plume.
 - o The conservative assumption that emissions from all six turbines combine into a single plume, which is also highly unlikely.
- Visibility impacts due to the Liquefaction Facility alone are below the 5% de minimis threshold at all Class I and Sensitive Class II areas except Lake Clark NP. Refinements to the ammonia background and the modeled facility normal operating scenario would mitigate modeled visibility impacts at all areas, and could easily reduce the impact at Lake Clark NP to below 5%.
- Cumulative predicted visibility impacts exceed the 10% threshold at all far-field Class I and Sensitive Class II areas, however:
 - o The elevated impacts are attributable to offsite sources based on a comparison of impacts with and without the Liquefaction Facility.
 - o Impacts due to the Liquefaction Facility are a negligible portion of the cumulative impact.
 - o A comparison of existing visibility measurements to cumulative modeled impacts at Tuxedni NWR and Denali NP indicates the model is over-predicting cumulative impacts. Impacts due to the Liquefaction Facility alone are also likely overly conservative (which are already generally below the source-only de minimis threshold).
- Deposition impacts due to the Liquefaction Facility alone are above the DAT at several Class I and Sensitive Class II areas, however:
 - o The actual fuel sulfur content of pipeline quality gas used at the facility would likely be less (by as much as half) than the 16 ppmv that was assumed in the modeling, which would mitigate modeled sulfur deposition impacts.
 - o Refinements to the modeled facility normal operating scenario would likely reduce both sulfur and nitrogen deposition impacts to below the DAT for all areas.
 - o If park-specific studies were available, there would be an opportunity to refine and increase the acceptable DATs, as current thresholds were designed to be protective of all Class I areas.
- Cumulative deposition impacts are within the DAT at all far field Class I and Sensitive Class II areas.

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Table 7-5: Liquefaction Facility-Only NAAQS/AAQs Air Quality Compliance Analysis – Normal Operations – Tuxedni NWR

Air Pollutant	Averaging Period	CALPUFF-Predicted Concentration (µg/m³)	Ambient Background Concentration (µg/m³)	Total Concentration (µg/m³)	NAAQS (µg/m³)	AAQs (µg/m³)
Sulfur Dioxide	1-Hour ^a	0.11	5.0	5.11	196	196
	3-Hour ^b	0.12	5.0	5.12	1,300	1,300
	24-Hour ^b	0.05	2.3	2.35	NA	365
	Annual ^d	0.00	0	0.00	NA	80
Carbon Monoxide	1-Hour ^b	5.67	1,145	1,151	40,000	40,000
	8-Hour ^b	3.04	1,145	1,148	10,000	10,000
Nitrogen Dioxide	1-Hour ^c	0.78	32.3	33.08	188	188
	Annual ^d	0.02	2.6	2.62	100	100
Particulate Matter less than 10 Microns	24-Hour ^f	0.34	40.0	40.34	150	150
Particulate Matter less than 2.5 Microns	24-Hour ^e	0.13	12.0	12.13	35	35
	Annual ^d	0.02	3.7	3.72	12	15

Table 7-6: Liquefaction Facility-Only NAAQS/AAQs Air Quality Compliance Analysis – Normal Operations – Denali NP

Air Pollutant	Averaging Period	CALPUFF-Predicted Concentration (µg/m³)	Ambient Background Concentration (µg/m³)	Total Concentration (µg/m³)	NAAQS (µg/m³)	AAQs (µg/m³)
Sulfur Dioxide	1-Hour ^a	0.10	5.0	5.10	196	196
	3-Hour ^b	0.10	5.0	5.10	1,300	1,300
	24-Hour ^b	0.04	2.3	2.34	NA	365
	Annual ^d	0.002	0	0.00	NA	80
Carbon Monoxide	1-Hour ^b	4.90	1,145	1,150	40,000	40,000
	8-Hour ^b	2.64	1,145	1,148	10,000	10,000
Nitrogen Dioxide	1-Hour ^c	0.63	32.3	32.93	188	188
	Annual ^d	0.02	2.6	2.62	100	100
Particulate Matter less than 10 Microns	24-Hour ^f	0.31	40.0	40.31	150	150
Particulate Matter less than 2.5 Microns	24-Hour ^e	0.10	12.0	12.10	35	35
	Annual ^d	0.01	3.7	3.71	12	15

Abbreviations:

NA = not applicable

µg/m³ = micrograms per cubic meter

Notes:

^a Value reported is the 99th percentile of the annual distribution of daily maximum values averaged over the 3-year period.

^b Value reported is the highest, second highest concentration of the values determined for each of the 3 modeled years.

^c Value reported is the 98th percentile of the annual distribution of daily maximum values averaged over the 3-year period.

^d Value reported is the maximum annual average concentration for the 3-year period.

^e Value reported is the 98th percentile averaged over the 3-year period.

^f Value reported is the highest, 6th highest concentration over the 3-year period.

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Table 7-7: Liquefaction Facility-Only NAAQS/AAQS Air Quality Compliance Analysis – Normal Operations – Kenai Fjords NP

Air Pollutant	Averaging Period	CALPUFF-Predicted Concentration (µg/m³)	Ambient Background Concentration (µg/m³)	Total Concentration (µg/m³)	NAAQS (µg/m³)	AAQS (µg/m³)
Sulfur Dioxide	1-Hour ^a	0.03	5.0	5.03	196	196
	3-Hour ^b	0.06	5.0	5.06	1,300	1,300
	24-Hour ^b	0.02	2.3	2.32	NA	365
	Annual ^d	0.0005	0	0.00	NA	80
Carbon Monoxide	1-Hour ^b	4.65	1,145	1,150	40,000	40,000
	8-Hour ^b	1.87	1,145	1,147	10,000	10,000
Nitrogen Dioxide	1-Hour ^c	0.39	32.3	32.69	188	188
	Annual ^d	0.003	2.6	2.60	100	100
Particulate Matter less than 10 Microns	24-Hour ^f	0.09	40.0	40.09	150	150
Particulate Matter less than 2.5 Microns	24-Hour ^e	0.03	12.0	12.03	35	35
	Annual ^d	0.006	3.7	3.71	12	15

Abbreviations:

NA = not applicable

µg/m³ = micrograms per cubic meter

Notes:

^a Value reported is the 99th percentile of the annual distribution of daily maximum values averaged over the 3-year period.

^b Value reported is the highest, second highest concentration of the values determined for each of the 3 modeled years.

^c Value reported is the 98th percentile of the annual distribution of daily maximum values averaged over the 3-year period.

^d Value reported is the maximum annual average concentration for the 3-year period.

^e Value reported is the 98th percentile averaged over the 3-year period.

^f Value reported is the highest, 6th highest concentration over the 3-year period.

Table 7-8: Liquefaction Facility-Only NAAQS/AAQS Air Quality Compliance Analysis – Normal Operations – Chugach NF

Air Pollutant	Averaging Period	CALPUFF-Predicted Concentration (µg/m³)	Ambient Background Concentration (µg/m³)	Total Concentration (µg/m³)	NAAQS (µg/m³)	AAQS (µg/m³)
Sulfur Dioxide	1-Hour ^a	0.07	5.0	5.07	196	196
	3-Hour ^b	0.07	5.0	5.07	1,300	1,300
	24-Hour ^b	0.03	2.3	2.33	NA	365
	Annual ^d	0.0008	0	0.00	NA	80
Carbon Monoxide	1-Hour ^b	4.60	1,145	1,150	40,000	40,000
	8-Hour ^b	2.08	1,145	1,147	10,000	10,000
Nitrogen Dioxide	1-Hour ^c	0.44	32.3	32.74	188	188
	Annual ^d	0.004	2.6	2.60	100	100
Particulate Matter less than 10 Microns	24-Hour ^f	0.07	40.0	40.07	150	150
Particulate Matter less than 2.5 Microns	24-Hour ^e	0.07	12.0	12.07	35	35
	Annual ^d	0.008	3.7	3.71	12	15

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Table 7-9: Liquefaction Facility-Only NAAQS/AAQS Air Quality Compliance Analysis – Normal Operations – Lake Clark NP

Air Pollutant	Averaging Period	CALPUFF-Predicted Concentration (µg/m³)	Ambient Background Concentration (µg/m³)	Total Concentration (µg/m³)	NAAQS (µg/m³)	AAQS (µg/m³)
Sulfur Dioxide	1-Hour ^a	0.13	5.0	5.13	196	196
	3-Hour ^b	0.13	5.0	5.13	1,300	1,300
	24-Hour ^b	0.06	2.3	2.36	NA	365
	Annual ^d	0.003	0	0.00	NA	80
Carbon Monoxide	1-Hour ^b	6.80	1,145	1152	40,000	40,000
	8-Hour ^b	3.36	1,145	1148	10,000	10,000
Nitrogen Dioxide	1-Hour ^c	0.78	32.3	33.08	188	188
	Annual ^d	0.02	2.6	2.62	100	100
Particulate Matter less than 10 Microns	24-Hour ^f	0.38	40.0	40.38	150	150
Particulate Matter less than 2.5 Microns	24-Hour ^e	0.14	12.0	12.14	35	35
	Annual ^d	0.02	3.7	3.72	12	15

Abbreviations:

NA = not applicable

µg/m³ = micrograms per cubic meter

Notes:

^a Value reported is the 99th percentile of the annual distribution of daily maximum values averaged over the 3-year period.

^b Value reported is the highest, second highest concentration of the values determined for each of the 3 modeled years.

^c Value reported is the 98th percentile of the annual distribution of daily maximum values averaged over the 3-year period.

^d Value reported is the maximum annual average concentration for the 3-year period.

^e Value reported is the 98th percentile averaged over the 3-year period.

^f Value reported is the highest, 6th highest concentration over the 3-year period.

Table 7-10: Liquefaction Facility-Only NAAQS/AAQS Air Quality Compliance Analysis – Normal Operations – Kodiak NWR

Air Pollutant	Averaging Period	CALPUFF-Predicted Concentration (µg/m³)	Ambient Background Concentration (µg/m³)	Total Concentration (µg/m³)	NAAQS (µg/m³)	AAQS (µg/m³)
Sulfur Dioxide	1-Hour ^a	5.01	5.0	10.01	196	196
	3-Hour ^b	5.01	5.0	10.01	1,300	1,300
	24-Hour ^b	2.35	2.3	4.65	NA	365
	Annual ^d	0.0002	0	0.00	NA	80
Carbon Monoxide	1-Hour ^b	1.10	1,145	1,146	40,000	40,000
	8-Hour ^b	0.61	1,145	1,146	10,000	10,000
Nitrogen Dioxide	1-Hour ^c	0.05	32.3	32.35	188	188
	Annual ^d	0.001	2.6	2.60	100	100
Particulate Matter less than 10 Microns	24-Hour ^f	0.02	40.0	40.02	150	150
Particulate Matter less than 2.5 Microns	24-Hour ^e	0.01	12.0	12.01	35	35
	Annual ^d	0.002	3.7	3.70	12	15

Abbreviations:

NA = not applicable

µg/m³ = micrograms per cubic meter

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Notes:

- ^a Value reported is the 99th percentile of the annual distribution of daily maximum values averaged over the 3-year period.
- ^b Value reported is the highest, second highest concentration of the values determined for each of the 3 modeled years.
- ^c Value reported is the 98th percentile of the annual distribution of daily maximum values averaged over the 3-year period.
- ^d Value reported is the maximum annual average concentration for the 3-year period.
- ^e Value reported is the 98th percentile averaged over the 3-year period.
- ^f Value reported is the highest, 6th highest concentration over the 3-year period.

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Table 7-11: Comparison of Liquefaction Facility-Only Model-Predicted Concentrations to Increment Thresholds – Tuxedni NWR

Air Pollutant	Averaging Period	CALPUFF-Predicted Concentration (µg/m ³)	Class I Increments (µg/m ³)
Sulfur Dioxide	1-Hour ^a	NA	NA
	3-Hour ^b	0.12	25
	24-Hour ^b	0.05	5
	Annual ^c	0.003	2
Carbon Monoxide	1-Hour ^a	NA	NA
	8-Hour ^a	NA	NA
Nitrogen Dioxide	1-Hour ^a	NA	NA
	Annual ^c	0.02	2.5
Particulate Matter less than 10 Microns	24-Hour ^b	0.34	8
	Annual ^c	0.02	4
Particulate Matter less than 2.5 Microns	24-Hour ^b	0.38	2
	Annual ^c	0.02	1

Table 7-12: Comparison of Liquefaction Facility-Only Model-Predicted Concentrations to Increment Thresholds – Denali NP

Air Pollutant	Averaging Period	CALPUFF-Predicted Concentration (µg/m ³)	Class I Increments (µg/m ³)
Sulfur Dioxide	1-Hour ^a	NA	NA
	3-Hour ^b	0.10	25
	24-Hour ^b	0.04	5
	Annual ^c	0.002	2
Carbon Monoxide	1-Hour ^a	NA	NA
	8-Hour ^a	NA	NA
Nitrogen Dioxide	1-Hour ^a	NA	NA
	Annual ^c	0.02	2.5
Particulate Matter less than 10 Microns	24-Hour ^b	0.31	8
	Annual ^c	0.01	4
Particulate Matter less than 2.5 Microns	24-Hour ^b	0.34	2
	Annual ^c	0.01	1

Abbreviations:

NA = not applicable

µg/m³ = micrograms per cubic meter

Notes:

^a Neither USEPA nor ADEC have established increment thresholds for 1-hour NO₂, 1-hour SO₂, 1-hour CO, or 8-hour CO.

^b Value reported is the maximum of the highest-second-high values from each of the five modeled years.

^c Value reported is the maximum annual average concentration for the 5-year period.

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Table 7-13: Comparison of Liquefaction Facility-Only Model-Predicted Concentrations to Increment Thresholds – Kenai Fjords NP

Air Pollutant	Averaging Period	CALPUFF-Predicted Concentration (µg/m ³)	Class II Increments (µg/m ³)
Sulfur Dioxide	1-Hour ^a	NA	NA
	3-Hour ^b	0.06	512
	24-Hour ^b	0.02	91
	Annual ^c	0.0005	20
Carbon Monoxide	1-Hour ^a	NA	NA
	8-Hour ^a	NA	NA
Nitrogen Dioxide	1-Hour ^a	NA	NA
	Annual ^c	0.003	25
Particulate Matter less than 10 Microns	24-Hour ^b	0.09	30
	Annual ^c	0.01	17
Particulate Matter less than 2.5 Microns	24-Hour ^b	0.10	9
	Annual ^c	0.01	4

Abbreviations:

NA = not applicable

µg/m³ = micrograms per cubic meter

Notes:

^a Neither USEPA nor ADEC have established increment thresholds for 1-hour NO₂, 1-hour SO₂, 1-hour CO, or 8-hour CO.

^b Value reported is the maximum of the highest-second-high values from each of the five modeled years.

^c Value reported is the maximum annual average concentration for the 5-year period.

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Table 7-14: Comparison of Liquefaction Facility-Only Model-Predicted Concentrations to Increment Thresholds – Chugach NF

Air Pollutant	Averaging Period	CALPUFF-Predicted Concentration (µg/m³)	Class II Increments (µg/m³)
Sulfur Dioxide	1-Hour ^a	NA	NA
	3-Hour ^b	0.07	512
	24-Hour ^b	0.03	91
	Annual ^c	0.001	20
Carbon Monoxide	1-Hour ^a	NA	NA
	8-Hour ^a	NA	NA
Nitrogen Dioxide	1-Hour ^a	NA	NA
	Annual ^c	0.004	25
Particulate Matter less than 10 Microns	24-Hour ^b	0.12	30
	Annual ^c	0.01	17
Particulate Matter less than 2.5 Microns	24-Hour ^b	0.15	9
	Annual ^c	0.01	4

Table 7-15: Comparison of Liquefaction Facility-Only Model-Predicted Concentrations to Increment Thresholds – Lake Clark NP

Air Pollutant	Averaging Period	CALPUFF-Predicted Concentration (µg/m³)	Class II Increments (µg/m³)
Sulfur Dioxide	1-Hour ^a	NA	NA
	3-Hour ^b	0.13	512
	24-Hour ^b	0.06	91
	Annual ^c	0.00	20
Carbon Monoxide	1-Hour ^a	NA	NA
	8-Hour ^a	NA	NA
Nitrogen Dioxide	1-Hour ^a	NA	NA
	Annual ^c	0.02	25
Particulate Matter less than 10 Microns	24-Hour ^b	0.38	30
	Annual ^c	0.02	17
Particulate Matter less than 2.5 Microns	24-Hour ^b	0.42	9
	Annual ^c	0.02	4

Abbreviations:

NA = not applicable

µg/m³ = micrograms per cubic meter

Notes:

^a Neither USEPA nor ADEC have established increment thresholds for 1-hour NO₂, 1-hour SO₂, 1-hour CO, or 8-hour CO.

^b Value reported is the maximum of the highest-second-high values from each of the five modeled years.

^c Value reported is the maximum annual average concentration for the 5-year period.

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Table 7-16: Comparison of Liquefaction Facility-Only Model-Predicted Concentrations to Increment Thresholds – Kodiak NWR

Air Pollutant	Averaging Period	CALPUFF-Predicted Concentration (µg/m ³)	Class II Increments (µg/m ³)
Sulfur Dioxide	1-Hour ^a	NA	NA
	3-Hour ^b	0.01	512
	24-Hour ^b	0.005	91
	Annual ^c	0.0002	20
Carbon Monoxide	1-Hour ^a	NA	NA
	8-Hour ^a	NA	NA
Nitrogen Dioxide	1-Hour ^a	NA	NA
	Annual ^c	0.02	25
Particulate Matter less than 10 Microns	24-Hour ^b	0.02	30
	Annual ^c	0.002	17
Particulate Matter less than 2.5 Microns	24-Hour ^b	0.02	9
	Annual ^c	0.003	4

Abbreviations:

NA = not applicable

µg/m³ = micrograms per cubic meter

Notes:

^a Neither USEPA nor ADEC have established increment thresholds for 1-hour NO₂, 1-hour SO₂, 1-hour CO, or 8-hour CO.

^b Value reported is the maximum of the highest-second-high values from each of the three modeled years.

^c Value reported is the maximum annual average concentration for the 3-year period.

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Table 7-17: Cumulative NAAQS/AAQS Air Quality Compliance Analysis – Normal Operations – Tuxedni NWR

Air Pollutant	Averaging Period	CALPUFF-Predicted Concentration (µg/m ³)	Ambient Background Concentration (µg/m ³)	Total Concentration (µg/m ³)	NAAQS (µg/m ³)	AAQS (µg/m ³)
Sulfur Dioxide	1-Hour ^a	0.70	5.0	5.70	196	196
	3-Hour ^b	0.68	5.0	5.68	1,300	1,300
	24-Hour ^b	0.32	2.3	2.62	NA	365
	Annual ^d	0.03	0	0.03	NA	80
Carbon Monoxide	1-Hour ^b	14.66	1,145	1,160	40,000	40,000
	8-Hour ^b	7.80	1,145	1,153	10,000	10,000
Nitrogen Dioxide	1-Hour ^c	4.79	32.3	37.09	188	188
	Annual ^d	0.22	2.6	2.82	100	100
Particulate Matter less than 10 Microns	24-Hour ^f	2.25	40.0	42.25	150	150
Particulate Matter less than 2.5 Microns	24-Hour ^e	0.93	12.0	12.93	35	35
	Annual ^d	0.12	3.7	3.82	12	15

Table 7-18: Cumulative NAAQS/AAQS Air Quality Compliance Analysis – Normal Operations – Denali NP

Air Pollutant	Averaging Period	CALPUFF-Predicted Concentration (µg/m ³)	Ambient Background Concentration (µg/m ³)	Total Concentration (µg/m ³)	NAAQS (µg/m ³)	AAQS (µg/m ³)
Sulfur Dioxide	1-Hour ^a	22.21	5.0	27.21	196	196
	3-Hour ^b	15.45	5.0	20.45	1,300	1,300
	24-Hour ^b	4.05	2.3	6.35	NA	365
	Annual ^d	0.258	0	0.26	NA	80
Carbon Monoxide	1-Hour ^b	46.63	1,145	1,192	40,000	40,000
	8-Hour ^b	17.34	1,145	1,162	10,000	10,000
Nitrogen Dioxide	1-Hour ^c	9.65	32.3	41.95	188	188
	Annual ^d	0.15	2.6	2.75	100	100
Particulate Matter less than 10 Microns	24-Hour ^f	2.22	40.0	42.22	150	150
Particulate Matter less than 2.5 Microns	24-Hour ^e	0.83	12.0	12.83	35	35
	Annual ^d	0.10	3.7	3.80	12	15

Abbreviations:

NA = not applicable

µg/m³ = micrograms per cubic meter

Notes:

^a Value reported is the 99th percentile of the annual distribution of daily maximum values averaged over the 3-year period.

^b Value reported is the highest, second highest concentration of the values determined for each of the 3 modeled years.

^c Value reported is the 98th percentile of the annual distribution of daily maximum values averaged over the 3-year period.

^d Value reported is the maximum annual average concentration for the 3-year period.

^e Value reported is the 98th percentile averaged over the 3-year period.

^f Value reported is the highest, 6th highest concentration over the 3-year period.

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Table 7-19: Cumulative NAAQS/AAQs Air Quality Compliance Analysis – Normal Operations – Kenai Fjords NP

Air Pollutant	Averaging Period	CALPUFF-Predicted Concentration (µg/m³)	Ambient Background Concentration (µg/m³)	Total Concentration (µg/m³)	NAAQS (µg/m³)	AAQs (µg/m³)
Sulfur Dioxide	1-Hour ^a	0.13	5.0	5.13	196	196
	3-Hour ^b	0.14	5.0	5.14	1,300	1,300
	24-Hour ^b	0.06	2.3	2.36	NA	365
	Annual ^d	0.0040	0	0.00	NA	80
Carbon Monoxide	1-Hour ^b	5.29	1,145	1,150	40,000	40,000
	8-Hour ^b	2.62	1,145	1,148	10,000	10,000
Nitrogen Dioxide	1-Hour ^c	0.79	32.3	33.09	188	188
	Annual ^d	0.016	2.6	2.62	100	100
Particulate Matter less than 10 Microns	24-Hour ^f	0.49	40.0	40.49	150	150
Particulate Matter less than 2.5 Microns	24-Hour ^e	0.17	12.0	12.17	35	35
	Annual ^d	0.025	3.7	3.72	12	15

Abbreviations:

NA = not applicable

µg/m³ = micrograms per cubic meter

Notes:

^a Value reported is the 99th percentile of the annual distribution of daily maximum values averaged over the 3-year period.

^b Value reported is the highest, second highest concentration of the values determined for each of the 3 modeled years.

^c Value reported is the 98th percentile of the annual distribution of daily maximum values averaged over the 3-year period.

^d Value reported is the maximum annual average concentration for the 3-year period.

^e Value reported is the 98th percentile averaged over the 3-year period.

^f Value reported is the highest, 6th highest concentration over the 3-year period.

Table 7-20: Cumulative NAAQS/AAQs Air Quality Compliance Analysis – Normal Operations – Chugach NF

Air Pollutant	Averaging Period	CALPUFF-Predicted Concentration (µg/m³)	Ambient Background Concentration (µg/m³)	Total Concentration (µg/m³)	NAAQS (µg/m³)	AAQs (µg/m³)
Sulfur Dioxide	1-Hour ^a	1.95	5.0	6.95	196	196
	3-Hour ^b	1.74	5.0	6.74	1,300	1,300
	24-Hour ^b	0.64	2.3	2.94	NA	365
	Annual ^d	0.0633	0	0.06	NA	80
Carbon Monoxide	1-Hour ^b	73.08	1,145	1,218	40,000	40,000
	8-Hour ^b	32.53	1,145	1,178	10,000	10,000
Nitrogen Dioxide	1-Hour ^c	17.45	32.3	49.75	188	188
	Annual ^d	0.687	2.6	3.29	100	100
Particulate Matter less than 10 Microns	24-Hour ^f	1.35	40.0	41.35	150	150
Particulate Matter less than 2.5 Microns	24-Hour ^e	1.35	12.0	13.35	35	35
	Annual ^d	0.182	3.7	3.88	12	15

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Table 7-21: Cumulative NAAQS/AAQs Air Quality Compliance Analysis – Normal Operations – Lake Clark NP

Air Pollutant	Averaging Period	CALPUFF-Predicted Concentration (µg/m³)	Ambient Background Concentration (µg/m³)	Total Concentration (µg/m³)	NAAQS (µg/m³)	AAQs (µg/m³)
Sulfur Dioxide	1-Hour ^a	1.31	5.0	6.31	196	196
	3-Hour ^b	1.10	5.0	6.10	1,300	1,300
	24-Hour ^b	0.42	2.3	2.72	NA	365
	Annual ^d	0.062	0	0.06	NA	80
Carbon Monoxide	1-Hour ^b	46.98	1,145	1,192	40,000	40,000
	8-Hour ^b	23.27	1,145	1,169	10,000	10,000
Nitrogen Dioxide	1-Hour ^c	11.97	32.3	44.27	188	188
	Annual ^d	0.54	2.6	3.14	100	100
Particulate Matter less than 10 Microns	24-Hour ^f	2.54	40.0	42.54	150	150
Particulate Matter less than 2.5 Microns	24-Hour ^e	1.44	12.0	13.44	35	35
	Annual ^d	0.19	3.7	3.89	12	15

Abbreviations:

NA = not applicable

µg/m³ = micrograms per cubic meter

Notes:

^a Value reported is the 99th percentile of the annual distribution of daily maximum values averaged over the 3-year period.

^b Value reported is the highest, second highest concentration of the values determined for each of the 3 modeled years.

^c Value reported is the 98th percentile of the annual distribution of daily maximum values averaged over the 3-year period.

^d Value reported is the maximum annual average concentration for the 3-year period.

^e Value reported is the 98th percentile averaged over the 3-year period.

^f Value reported is the highest, 6th highest concentration over the 3-year period.

Table 7-22: Cumulative NAAQS/AAQs Air Quality Compliance Analysis – Normal Operations – Kodiak NWR

Air Pollutant	Averaging Period	CALPUFF-Predicted Concentration (µg/m³)	Ambient Background Concentration (µg/m³)	Total Concentration (µg/m³)	NAAQS (µg/m³)	AAQs (µg/m³)
Sulfur Dioxide	1-Hour ^a	0.01	5.0	5.01	196	196
	3-Hour ^b	0.01	5.0	5.01	1,300	1,300
	24-Hour ^b	0.05	2.3	2.35	NA	365
	Annual ^d	0.0002	0	0.00	NA	80
Carbon Monoxide	1-Hour ^b	1.10	1,145	1,146	40,000	40,000
	8-Hour ^b	0.61	1,145	1,146	10,000	10,000
Nitrogen Dioxide	1-Hour ^c	0.05	32.3	32.35	188	188
	Annual ^d	0.001	2.6	2.60	100	100
Particulate Matter less than 10 Microns	24-Hour ^f	0.02	40.0	40.02	150	150
Particulate Matter less than 2.5 Microns	24-Hour ^e	0.01	12.0	12.01	35	35
	Annual ^d	0.002	3.7	3.70	12	15

Abbreviations:

NA = not applicable

µg/m³ = micrograms per cubic meter

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Notes:

- ^a Value reported is the 99th percentile of the annual distribution of daily maximum values averaged over the 3-year period.
- ^b Value reported is the highest, second highest concentration of the values determined for each of the 3 modeled years.
- ^c Value reported is the 98th percentile of the annual distribution of daily maximum values averaged over the 3-year period.
- ^d Value reported is the maximum annual average concentration for the 3-year period.
- ^e Value reported is the 98th percentile averaged over the 3-year period.
- ^f Value reported is the highest, 6th highest concentration over the 3-year period.

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Table 7-23: Comparison of Cumulative Model-Predicted Concentrations to Increment Thresholds – Tuxedni NWR

Air Pollutant	Averaging Period	CALPUFF-Predicted Concentration (µg/m³)	Class I Increments (µg/m³)
Sulfur Dioxide	1-Hour ^a	NA	NA
	3-Hour ^b	0.64	25
	24-Hour ^b	0.30	5
	Annual ^c	0.03	2
Carbon Monoxide	1-Hour ^a	NA	NA
	8-Hour ^a	NA	NA
Nitrogen Dioxide	1-Hour ^a	NA	NA
	Annual ^c	0.18	2.5
Particulate Matter less than 10 Microns	24-Hour ^b	1.74	8
	Annual ^c	0.10	4
Particulate Matter less than 2.5 Microns	24-Hour ^b	1.78	2
	Annual ^c	0.10	1

Table 7-24: Comparison of Cumulative Model-Predicted Concentrations to Increment Thresholds – Denali NP

Air Pollutant	Averaging Period	CALPUFF-Predicted Concentration (µg/m³)	Class I Increments (µg/m³)
Sulfur Dioxide	1-Hour ^a	NA	NA
	3-Hour ^b	15.45	25
	24-Hour ^b	4.05	5
	Annual ^c	0.26	2
Carbon Monoxide	1-Hour ^a	NA	NA
	8-Hour ^a	NA	NA
Nitrogen Dioxide	1-Hour ^a	NA	NA
	Annual ^c	0.12	2.5
Particulate Matter less than 10 Microns	24-Hour ^b	1.67	8
	Annual ^c	0.08	4
Particulate Matter less than 2.5 Microns	24-Hour ^b	1.76	2
	Annual ^c	0.08	1

Abbreviations:

NA = not applicable

µg/m³ = micrograms per cubic meter

Notes:

^a Neither USEPA nor ADEC have established increment thresholds for 1-hour NO₂, 1-hour SO₂, 1-hour CO, or 8-hour CO.

^b Value reported is the maximum of the highest-second-high values from each of the five modeled years.

^c Value reported is the maximum annual average concentration for the 5-year period.

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Table 7-25: Comparison of Cumulative Model-Predicted Concentrations to Increment Thresholds – Kenai Fjords NP

Air Pollutant	Averaging Period	CALPUFF-Predicted Concentration (µg/m ³)	Class II Increments (µg/m ³)
Sulfur Dioxide	1-Hour ^a	NA	NA
	3-Hour ^b	0.13	512
	24-Hour ^b	0.05	91
	Annual ^c	0.004	20
Carbon Monoxide	1-Hour ^a	NA	NA
	8-Hour ^a	NA	NA
Nitrogen Dioxide	1-Hour ^a	NA	NA
	Annual ^c	0.02	25
Particulate Matter less than 10 Microns	24-Hour ^b	0.40	30
	Annual ^c	0.02	17
Particulate Matter less than 2.5 Microns	24-Hour ^b	0.42	9
	Annual ^c	0.03	4

Abbreviations:

NA = not applicable

µg/m³ = micrograms per cubic meter

Notes:

^a Neither USEPA nor ADEC have established increment thresholds for 1-hour NO₂, 1-hour SO₂, 1-hour CO, or 8-hour CO.

^b Value reported is the maximum of the highest-second-high values from each of the five modeled years.

^c Value reported is the maximum annual average concentration for the 5-year period.

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Table 7-26: Comparison of Cumulative Model-Predicted Concentrations to Increment Thresholds – Chugach NF

Air Pollutant	Averaging Period	CALPUFF-Predicted Concentration (µg/m³)	Class II Increments (µg/m³)
Sulfur Dioxide	1-Hour ^a	NA	NA
	3-Hour ^b	1.74	512
	24-Hour ^b	0.64	91
	Annual ^c	0.06	20
Carbon Monoxide	1-Hour ^a	NA	NA
	8-Hour ^a	NA	NA
Nitrogen Dioxide	1-Hour ^a	NA	NA
	Annual ^c	0.68	25
Particulate Matter less than 10 Microns	24-Hour ^b	2.37	30
	Annual ^c	0.18	17
Particulate Matter less than 2.5 Microns	24-Hour ^b	2.46	9
	Annual ^c	0.19	4

Table 7-27: Comparison of Cumulative Model-Predicted Concentrations to Increment Thresholds – Lake Clark NP

Air Pollutant	Averaging Period	CALPUFF-Predicted Concentration (µg/m³)	Class II Increments (µg/m³)
Sulfur Dioxide	1-Hour ^a	NA	NA
	3-Hour ^b	1.10	512
	24-Hour ^b	0.42	91
	Annual ^c	0.06	20
Carbon Monoxide	1-Hour ^a	NA	NA
	8-Hour ^a	NA	NA
Nitrogen Dioxide	1-Hour ^a	NA	NA
	Annual ^c	0.52	25
Particulate Matter less than 10 Microns	24-Hour ^b	2.15	30
	Annual ^c	0.19	17
Particulate Matter less than 2.5 Microns	24-Hour ^b	2.36	9
	Annual ^c	0.20	4

Abbreviations:

NA = not applicable

µg/m³ = micrograms per cubic meter

Notes:

^a Neither USEPA nor ADEC have established increment thresholds for 1-hour NO₂, 1-hour SO₂, 1-hour CO, or 8-hour CO.

^b Value reported is the maximum of the highest-second-high values from each of the five modeled years.

^c Value reported is the maximum annual average concentration for the 5-year period.

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Table 7-28: Comparison of Cumulative Model-Predicted Concentrations to Increment Thresholds – Kodiak NWR

Air Pollutant	Averaging Period	CALPUFF-Predicted Concentration (µg/m³)	Class II Increments (µg/m³)
Sulfur Dioxide	1-Hour ^a	NA	NA
	3-Hour ^b	2.62	512
	24-Hour ^b	0.63	91
	Annual ^c	0.07	20
Carbon Monoxide	1-Hour ^a	NA	NA
	8-Hour ^a	NA	NA
Nitrogen Dioxide	1-Hour ^a	NA	NA
	Annual ^c	0.03	25
Particulate Matter less than 10 Microns	24-Hour ^b	0.40	30
	Annual ^c	0.02	17
Particulate Matter less than 2.5 Microns	24-Hour ^b	0.50	9
	Annual ^c	0.03	4

Abbreviations:

NA = not applicable

µg/m³ = micrograms per cubic meter

Notes:

^a Neither USEPA nor ADEC have established increment thresholds for 1-hour NO₂, 1-hour SO₂, 1-hour CO, or 8-hour CO.

^b Value reported is the maximum of the highest-second-high values from each of the three modeled years.

^c Value reported is the maximum annual average concentration for the 3-year period.

^a

Table 7-29: VISCREEN Predicted Impacts Inside Kenai National Wildlife Refuge (Sky Background)

Source Plume ^a	Observer Location	Scattering Angle (deg)	Perceptibility (ΔE)		Contrast (Cp)	
			Criteria	Modeled	Criteria	Modeled
Forward Scatter						
Compressor Turbine	Closest Park Boundary	10	2.00	1.30	±0.05	-0.02
	Skilak Lake	10	2.00	0.39	±0.05	-0.01
Power Generators	Closest Park Boundary	10	2.00	0.38	±0.05	-0.01
	Skilak Lake	10	2.00	0.12	±0.05	0.00
LP Flare + TH Oxidizer	Closest Park Boundary	10	2.00	0.01	±0.05	0.00
	Skilak Lake	10	2.00	0.00	±0.05	0.00
Wet/Dry Flares	Closest Park Boundary	10	2.00	0.01	±0.05	0.00
	Skilak Lake	10	2.00	0.01	±0.05	0.00
Marine	Closest Park Boundary	10	2.00	0.91	±0.05	-0.01
	Skilak Lake	10	2.00	0.33	±0.05	-0.01
Backward Scatter						
Compressor Turbine	Closest Park Boundary	140	2.00	2.39	±0.05	-0.067
	Skilak Lake	140	2.00	0.86	±0.05	-0.03

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Power Generators	Closest Park Boundary	140	2.00	0.66	±0.05	-0.02
	Skilak Lake	140	2.00	0.24	±0.05	-0.01
LP Flare + TH Oxidizer	Closest Park Boundary	140	2.00	0.01	±0.05	0.00
	Skilak Lake	140	2.00	0.01	±0.05	0.00
Wet/Dry Flares	Closest Park Boundary	140	2.00	0.02	±0.05	0.00
	Skilak Lake	140	2.00	0.01	±0.05	0.00
Marine	Closest Park Boundary	140	2.00	0.78	±0.05	-0.02
	Skilak Lake	140	2.00	0.24	±0.05	-0.01

Notes:

^a See Table 6-4 for discussion regarding how individual sources were combined into these 5 separate plume impact assessments.

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Table 7-30: VISCREEN Predict ed Imp acts Ins ide Kenai Natio nal Wildlif e Refuge (Terrain Background)

Source Plume ^a	Observer Location	Scattering Angle (deg)	Perceptibility (ΔE)		Contrast (Cp)	
			Criteria	Modeled	Criteria	Modeled
Forward Scatter						
Compressor Turbine	Closest Park Boundary	10	2.00	5.63	±0.05	0.02
	Skilak Lake	10	2.00	2.15	±0.05	0.03
Power Generators	Closest Park Boundary	10	2.00	1.61	±0.05	0.01
	Skilak Lake	10	2.00	0.60	±0.05	0.01
LP Flare + TH Oxidizer	Closest Park Boundary	10	2.00	0.04	±0.05	0.00
	Skilak Lake	10	2.00	0.01	±0.05	0.00
Wet/Dry Flares	Closest Park Boundary	10	2.00	0.07	±0.05	0.00
	Skilak Lake	10	2.00	0.03	±0.05	0.00
Marine	Closest Park Boundary	10	2.00	0.68	±0.05	0.00
	Skilak Lake	10	2.00	0.46	±0.05	0.01
Backward Scatter						
Compressor Turbine	Closest Park Boundary	140	2.00	0.46	±0.05	0.00
	Skilak Lake	140	2.00	0.75	±0.05	0.02
Power Generators	Closest Park Boundary	140	2.00	0.12	±0.05	0.00
	Skilak Lake	140	2.00	0.21	±0.05	0.01
LP Flare + TH Oxidizer	Closest Park Boundary	140	2.00	0.00	±0.05	0.00
	Skilak Lake	140	2.00	0.00	±0.05	0.00
Wet/Dry Flares	Closest Park Boundary	140	2.00	0.01	±0.05	0.00
	Skilak Lake	140	2.00	0.01	±0.05	0.00
Marine	Closest Park Boundary	140	2.00	0.11	±0.05	0.00
	Skilak Lake	140	2.00	0.20	±0.05	0.01

Notes:

^a See Table 6-4 for discussion regarding how individual sources were combined into these 5 separate plume impact assessments.

Table 7-31: Liquefaction Facility-Only Regional Haze Results

Class I/II Area	Year	Number of Days with Extinction Above		8th Highest Change in Extinction (%)	Visibility Extinction Threshold for a Project (%)
		5%	10%		
Tuxedni NWR	2002	2	0	2.9	5.0
	2003	1	0	3.5	5.0
	2004	5	0	4.5	5.0
Denali NP	2002	2	0	2.8	5.0
	2003	2	0	3.1	5.0
	2004	3	0	3.7	5.0
Kenai Fjords NP	2002	0	0	1.6	5.0
	2003	0	0	2.0	5.0
	2004	0	0	1.5	5.0
Chugach NF	2002	2	0	2.9	5.0
	2003	0	0	2.8	5.0
	2004	1	0	2.9	5.0
Lake Clark NP	2002	7	0	4.9	5.0
	2003	8	0	5.1	5.0
	2004	13	0	5.3	5.0
Kodiak NWR	2002	0	0	0.5	5.0
	2003	0	0	0.4	5.0
	2004	0	0	0.4	5.0

Table 7-32: Cumulative Regional Haze Results

Class I/II Area	Year	Number of Days with Extinction Above		8th Highest Change in Extinction (%)	Cumulative Visibility Extinction Threshold (%)
		5%	10%		
Tuxedni NWR	2002	144	70	24.5	10.0
	2003	136	67	28.5	10.0
	2004	142	75	25.3	10.0
Denali NP	2002	194	100	46.7	10.0
	2003	198	102	53.3	10.0
	2004	208	127	47.8	10.0
Kenai Fjords NP	2002	35	9	11.3	10.0
	2003	35	8	10.2	10.0
	2004	26	2	7.5	10.0
Chugach NF	2002	214	121	34.8	10.0
	2003	220	136	38.2	10.0
	2004	206	113	43.9	10.0
Lake Clark NP	2002	261	157	40.2	10.0
	2003	243	138	40.3	10.0
	2004	261	153	50.8	10.0
Kodiak NWR	2002	29	10	11.2	10.0
	2003	46	9	10.3	10.0
	2004	32	11	13.2	10.0

Table 7-33: Liquefaction Facility-Only Sulfur Deposition Results

Class I/II Area	Year	Sulfur Predicted Impact (kg/ha/yr)	NPS Class I Deposition Analysis Thresholds (kg/ha/yr)	Percent of DAT
Tuxedni NWR	3-Year Max	5.188E-03	0.005	104
Denali NP	3-Year Max	3.701E-03	0.005	74
Kenai NWR	3-Year Max	5.796E-03	0.005	116
Kenai Fjords NP	3-Year Max	2.943E-04	0.005	6
Chugach NF	3-Year Max	9.726E-04	0.005	19
Lake Clark NP	3-Year Max	5.931E-03	0.005	119
Kodiak NWR	3-Year Max	2.238E-04	0.005	4

Table 7-34: Liquefaction Facility-Only Nitrogen Deposition Results

Class I/II Area	Year	Nitrogen Predicted Impact (kg/ha/yr)	NPS Class I Deposition Analysis Thresholds (kg/ha/yr)	Percent of DAT
Tuxedni NWR	3-Year Max	1.359E-02	0.005	272
Denali NP	3-Year Max	1.433E-02	0.005	287
Kenai NWR	3-Year Max	3.135E-02	0.005	627
Kenai Fjords NP	3-Year Max	1.953E-03	0.005	39
Chugach NF	3-Year Max	4.775E-03	0.005	95
Lake Clark NP	3-Year Max	1.966E-02	0.005	393
Kodiak NWR	3-Year Max	2.096E-03	0.005	42

Table 7-35: Cumulative Sulfur Deposition Results

Class I/II Area	Year	Sulfur Predicted Impact (kg/ha/yr)	NPS Class I Deposition Analysis Thresholds (kg/ha/yr)	Percent of DAT
Tuxedni NWR	3-Year Max	5.42E-02	0.125	43
Denali NP	3-Year Max	7.95E-02	0.125	64
Kenai Fjords NP	3-Year Max	2.44E-03	0.125	2
Chugach NF	3-Year Max	3.00E-02	0.125	24
Lake Clark NP	3-Year Max	5.28E-02	0.125	42
Kodiak NWR	3-Year Max	2.70E-02	0.125	22

Table 7-36: Cumulative Nitrogen Deposition Results

Class I/II Area	Year	Nitrogen Predicted Impact (kg/ha/yr)	NPS Class I Deposition Analysis Thresholds (kg/ha/yr)	Percent of DAT
Tuxedni NWR	3-Year Max	1.19E-01	0.125	95
Denali NP	3-Year Max	9.34E-02	0.125	75
Kenai Fjords NP	3-Year Max	1.37E-02	0.125	11
Chugach NF	3-Year Max	7.31E-02	0.125	58
Lake Clark NP	3-Year Max	1.22E-01	0.125	98
Kodiak NWR	3-Year Max	1.82E-02	0.125	15

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8.0 ASSESSMENT OF OZONE AND SECONDARY PARTICULATE IMPACTS

8.1 UNDERSTANDING OZONE CONCENTRATIONS

8.1.1 Ozone Chemical Processes

Ozone is not directly omitted from the Liquefaction Facility, therefore, any impacts to ambient ozone as a result of Liquefaction Facility precursor emissions requires an understanding of conditions resulting in ozone formation and destruction in the project area and the possible role that source emissions could play in that formation.

8.1.1.1 Conditions for Ozone Formation

Ground level ozone is more accurately referred to as tropospheric ozone. Tropospheric ozone is formed from the chemical reaction between Volatile Organic Compounds (VOC) and NO_x . In general ozone concentrations tend to peak near urban-suburban areas, where there are higher amounts of VOC and NO_x emissions. Ozone concentrations tend to decrease in rural locations and more remote locations. Since ozone is formed in the atmosphere, rather than directly emitted, VOC and NO_x emissions are referred to as ozone precursor emissions or 'ozone precursors'.

Energy is required to initiate the chemical reactions that form ozone. Commonly this energy is provided by solar radiation. The chemical reaction is initiated by a process called photolysis, which is when molecules are separated by the action of light. Since the reactions that form ozone are driven by solar radiation, ozone is formed more rapidly on sunny days. In the northern hemisphere available solar energy peaks during the summer, although during other times of the year if the surface is highly reflective (such as when there is snow cover) the solar energy can be high enough to form ozone in the presence of ozone precursors.

8.1.1.2 Ozone Formation Chemical Mechanisms

Tropospheric ozone formation is initiated by photolysis of NO_2 . This step begins a series of complex and highly diverse chemical reactions that both produce and destroy ozone in the atmosphere. The exact chemical reactions depend on the presence of multiple chemical compounds in the atmosphere. At the heart of the ozone formation process is the hydroxyl radical (OH). The OH radical can react with either VOC or NO_x . When there is more VOC in the atmosphere than NO_x (which is referred to as a high VOC-to- NO_x ratio) the OH radical will mainly react with VOC, at low VOC-to- NO_x ratios the OH radical predominately reacts with NO_x .

At a given VOC-to- NO_x ratio, the OH will react equally with both compounds. This given value represents the maximum ozone formation, for ratios of VOC-to- NO_x less than this optimum ratio, OH reacts predominantly with NO_2 removing radicals and retarding ozone formation. Under these conditions a reduction of NO_x favors ozone formation. On the other hand, under very low NO_x concentrations (high VOC-to- NO_x ratios) a decrease in NO_x favors certain reactions among peroxy radicals which retard ozone formation.

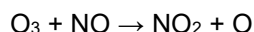
This complex chemistry implies that ozone production is not simply proportional to the amount of NO_x present. At a given level of VOC, there is a NO_x concentration that will maximize ozone production that is an optimum VOC-to- NO_x ratio. For ratios less than this optimum ratio NO_x increases lead to ozone decreases. Urban centers and areas immediately downwind of recently emitted NO_x (which is predominately emitted in the form of nitrogen oxide [NO]) tend to have sufficiently low VOC-to- NO_x ratios that ozone is destroyed rather than formed. In contrast, rural environments tend to have higher VOC-to- NO_x ratios due to the predominance of natural VOC

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emissions from plants (referred to as “biogenic” sources). In effect in most areas, except in areas with fresh NO_x emissions, the availability of NO_x governs ozone production.

8.1.1.3 Ozone Destruction Processes

Ozone formation has a non-linear relationship with its precursors. In particular for NO_x, a process called NO_x titration occurs in the immediate vicinity of NO sources. Fresh NO emissions are emitted from combustion sources such as power plants and mobile sources. When NO_x titrates ozone, ozone is removed by reaction with NO to regenerate nitrogen dioxide (NO₂) following this reaction:



During the daytime this reaction is normally balanced by the photolysis of NO₂ that produces atomic oxygen and subsequent ozone. However in the vicinity of large NO emissions during nighttime, the result is the net conversion of ozone to NO₂. This process can be considered as an ozone sink. In addition, high NO₂ concentrations deflect the initial oxidation step of VOCs by forming other products such as nitric acid (HNO₃) which prevent the net formation of ozone.

In addition to the destruction paths indicated above, in Polar Regions during the springtime unique photochemistry converts inert halide salt ions into reactive halogen species that deplete ozone in the boundary layer to near zero levels (Simpson et al. 2007, Oltmans et al. 2012, Helmig et al. 2012, Thompson et al. 2015). These ozone depletion events (ODEs) were first discovered in the 1980s and great advances have been made to understand their dynamics, but many key processes remain poorly understood. It is known that the ODEs are caused by active halogen photochemistry resulting from halogen atom precursors emitted from snow, ice or aerosol surfaces. The role of bromine has been generally accepted, but much less is known about the roles of chlorine and iodine radicals in the ozone depletion chemistry (Simpson et al. 2007, Thompson et al. 2015). The main source of reactive bromine species is bromide from sea salt that is released via a series of photochemical and heterogeneous reactions known as the bromine explosion. ODEs can influence the chemistry in the polar troposphere as it leads to a shift in oxidants and oxidation products. In particular, ozone depletion and halogen chemistry have a significant impact on VOC photochemistry by leading to the rapid destruction of alkanes, alkenes and most aromatics.

8.1.2 Ozone Lifetimes

8.1.2.1 Ozone Lifetime

Tropospheric ozone has two main sources: transport from upper levels of the atmosphere (stratospheric ozone) and photochemical production near the surface. The two main processes involved in the loss of tropospheric ozone are: chemical destruction and uptake of ozone at the surface of the earth (dry deposition). Ozone lifetimes in the troposphere vary significantly depending on altitude, latitude and season. Ozone lifetimes could easily vary between 5 to 30 days. Stevenson et al. (2006) analyzed global tropospheric ozone distributions and lifetimes using an ensemble of 26 atmospheric chemistry models and found a mean ozone lifetime of 22 days. These values imply that once formed, ozone could be subjected to meteorological transport over significant regional scales.

Stohl (2006) developed a climatology of transport in and to the Arctic based on a Lagrangian particle dispersion model. Stohl found that the time spent by air masses continuously north of 70°N or Arctic Age is highest near the surface in North America. North of 80°N, near the surface the mean Arctic age is 1 week in winter and 2 weeks in summer. For ozone in particular, sunlight fuels photolysis reactions and plays an important role in the atmospheric chemistry. In the Arctic winter, however its absence completely inhibits the photochemistry and is then important to estimate how long Arctic air is exposed to continuous darkness and how frequently it travels south escaping polar night. Stohl found that the time in complete darkness spent by an air mass in North America is about 10

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to 14 days during December. Importantly Stohl also was able to determine three major pathways in which air pollution can be transported into the Arctic: low-level transport followed by ascent in the Arctic, low-level transport alone, and uplift outside the Arctic, followed by descent in the Arctic. Sensitivities of Arctic masses to air pollutant emissions indicate that they are the highest over Siberia and Europe in winter and over the oceans in summer. Stratospheric intrusion was found to be much slower in the Arctic than in midlatitudes.

8.1.2.2 Source and Distance Relationship on Ozone Concentrations

Typically as an air mass moves away from an urban center, the VOC-to-NO_x ratio changes due to further photochemical reactions, meteorological processes and the influence of fresh emissions. Usually the concentrations of NO_x decrease faster than that of VOC because of the presence of fresh biogenic emissions. Thus the VOC-to-NO_x ratios increase as one moves away from urban centers and in more suburban, rural, and remote regions the formation of ozone becomes mainly NO_x limited. The photochemistry in urban plumes proceeds relatively fast as the oxidation of VOCs leads to increased ozone over a short period of time and to a faster removal of NO_x. Hence the regime where ozone formation is controlled by the concentration of NO_x is reached sooner.

Baker et al. (2016) performed photochemical modeling simulations of 24 hypothetical single sources in the continental United State to estimate their impacts in ozone concentrations. The modeling showed that downwind impacts varied directionally from each source due to differences in meteorology and chemical environment near the source. An aggregate analysis of maximum daily 8-hour ozone impacts as a function of the distance from the source shows that maximum impacts are not located in close proximity to the modeled emissions sources, but after the peak impact is reached, the ozone concentrations decrease as the distance increases.

8.1.3 Existing Ozone Concentrations

At remote locations, natural background ozone concentrations can range between 20 and 40 ppbv. Sources of natural ozone include stratospheric intrusions, wildfires, lightning and vegetation (a.k.a. biogenic sources). Also it is recognized that even sites located in remote regions can measure ozone which originated from manmade sources. Detailed analysis on the sources contributing to background ozone using a combination of measurements and photochemical grid modeling does not exist for the state of Alaska; however, observations (Vingarzan 2004) show that hourly median ozone concentrations in Denali National Park range between 29 and 34 ppbv, while the ozone annual means range between 23 and 29 ppbv at Point Barrow, AK.

8.2 UNDERSTANDING SECONDARY PARTICULATE CONCENTRATIONS

Aerosols also known as particulate matter (PM) are solids or liquids suspended in the atmosphere that have diameters that range from 0.001 up to 100 micrometers (µm). Although aerosols could have multiple sizes, generally those that have diameters less than 2.5 µm are classified as “fine”, while anything larger than 2.5 µm would be known as “coarse”. The sources and chemical compositions of fine and coarse particles are different. In general coarse particles are produced by mechanical processes and consist of soil dust, sea salt, fly ash, etc. Fine particles consist of both primary particles from combustion and secondary particles that are formed in the atmosphere as the results of various chemical reactions and gas-to-particle conversion; it consists of sulfates, nitrates, ammonium, secondary organics, etc. USEPA has developed standards for particulate with a diameter less than 10 µm (PM₁₀) and those with a diameter less than 2.5 µm (PM_{2.5}). This Section focuses on secondary particles since these cannot be modeled in the near-field using models approved in the Modeling Guideline.

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8.2.1 Particle Formation and Lifetimes

Fine particles undergo a series of complex processes that ultimately lead to their formation and establish their atmospheric lifetimes. Generally, fine particles are subject to the general formation and removal pathways:

Nucleation. This process describes the rate at which a transformation of phase occurs as the very first small nuclei appear. The nucleation of trace substances and water from the vapor phase to the liquid or solid phase is of primary concern in the atmosphere. Heterogeneous nucleation is the nucleation on a foreign surface or substance and it readily allows the formation in air of water droplets when the relative humidity is only slightly above 100%.

Chemical reactions. A significant amount of chemical reactions occur between gas phase precursors that eventually lead to the formation of particulate matter in the atmosphere. Generally hundreds to thousands of chemical reactions occur depending on the chemical species involved. The ultimate compositions of these particulates in the atmosphere include sulfate, nitrate, ammonium, elemental carbon, organic compounds, water, and metals.

Condensation. This process involves particle populations and it refers to vapor that condenses on particles or when material evaporates from the aerosol to the gas phase. This process tends to change the size of the particles; usually the growth of the particles is governed by the diffusion coefficient for each species as well as the vapor pressure difference between chemical species and the equilibrium vapor pressure.

Coagulation. This process involves particle growth as the result of one or more particles suspended in the atmosphere colliding as a result of Brownian motion or other hydrodynamic, electrical, gravitational or other forces.

Cloud processing and removal. Aerosols can activate under supersaturation conditions and lead to the formation of cloud droplets, in other words they act as cloud condensation nuclei. Once processed in this manner they could be removed from the atmosphere following precipitation events or they could also undergo aqueous phase chemistry. Finally, precipitation can also remove a significant number of particles from the atmosphere as the cloud droplets interact with aerosols.

Fine particles are usually the result of the processes mentioned above and in many instances they are formed in the atmosphere. PM_{2.5} generally is composed of particles that had multiple sources such as combustion (coal, oil, gasoline, diesel, wood, etc.) and gas to particle conversion of precursors such as NO_x, SO₂ and VOCs.

8.2.2 PM_{2.5} Lifetimes

8.2.2.1 PM_{2.5} Lifetime

The estimated lifetime of PM_{2.5} in the troposphere varies significantly depending on altitude, latitude and season. PM_{2.5} lifetimes could easily vary between a few days up to several weeks. Once formed, particles could be subjected to meteorological transport over significant regional scales that range from hundreds to thousands of miles.

A summary of the characteristics of atmospheric transport of precursors into the Arctic troposphere was presented in Section 8.1.2.1 above. Those same characteristics affect the lifetime of particulates in the Arctic. An important consideration in the lifetime of particulate nitrate and sulfate, which are PM components usually associated to anthropogenic sources, is the availability of ammonia. Ammonia is the dominant alkaline gas in the atmosphere and plays an important role in the formation of ammonium nitrate or sulfate, thus is important to quantify its magnitude and location. In midlatitudes major sources of ammonia include agriculture, vegetation, transport and industry, but these are expected to contribute minimally in the Arctic Circle. Ammonia is short lived in the atmosphere so is unlikely that long range transport would bring significant amounts of

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ammonia from lower latitudes. Biomass burning could inject important amounts of ammonia, so wildfires could play an important episodic role. In remote marine environments, the ocean is the dominant source of ammonia by remineralization of organic matter by bacteria and phytoplankton excretion (Carpenter et al. 2012). During the summertime, it is expected that this also will be the most important source of ammonia in the Arctic. Wentworth et al. (2016) have been able to determine that ammonia concentrations in the Arctic could range between 0.03 and 0.6 $\mu\text{g}/\text{m}^3$ (0.040 – 0.870 ppbv) during the summer, which is 1 to 2 orders of magnitude lower than typical ammonia concentrations over the continental U.S (0.1 to 10 ppbv).

8.2.2.2 Source and Distance Relationship on PM_{2.5} Concentrations

The spatial distribution of PM_{2.5} over large distances from a single source is in part a function of the chemical species involved. For instance particles that contain significant amounts of sulfate will be longer lived in the atmosphere than those with only nitrate, because nitrate is semi-volatile and thus able to convert back into the gas phase. Other more inert species like fine dust will be subjected to dispersion and gravitational settling without their lifetimes being significantly affected by chemical processes.

Baker et al. (2016) performed photochemical modeling simulations of 24 hypothetical single sources in the continental United State to estimate their impacts in ozone and PM_{2.5} concentrations. The modeling showed that downwind impacts varied directionally from each source due to differences in meteorology and chemical environment near the source. An aggregate analysis of daily maximum 24-hour average PM_{2.5} impacts as a function of the distance from the source shows that maximum impacts from secondary formation are not located in close proximity to the modeled emissions sources, but after the peak direct PM_{2.5} impact is reached but somewhere less than 50 kilometers downwind, the PM_{2.5} concentrations decrease as the distance increases.

8.2.3 Existing PM_{2.5} Concentrations

There is no typical or uniform ambient background concentration of PM_{2.5} given that it could be composed by multiple chemical species. Urban environments' in the continental U.S. typically have some of the highest PM_{2.5} concentrations that could exceed more than 12 $\mu\text{g}/\text{m}^3$ on an annual average. Rural and remote environments will usually show both different compositions and lower annual concentrations that could range from 5 to 10 $\mu\text{g}/\text{m}^3$. However some areas might be influenced by desert aerosols, which originate in deserts from wind disturbance but could extend considerably over adjacent regions. It is well documented that dust storms from the Sahara could transfer material across the Atlantic Ocean and affect the east coast of the United States. Also coastal areas might be influenced by marine aerosols.

The Liquefaction Facility is located close to Anchorage, Alaska. Kim and Hopke (2008) performed a characterization of ambient fine particles using source apportionment techniques in the Northwestern U.S. and Anchorage. They found that gasoline vehicles, secondary sulfates, and wood smoke were the largest sources of PM_{2.5} in the region. Secondary sulfates showed an April peak in Anchorage which they linked to increased photochemical reactions and long range transport. Ward et al. (2012) performed a source apportionment study in the subarctic air shed of Fairbanks, Alaska. They found that PM_{2.5} concentrations average between 22 and 26 $\mu\text{g}/\text{m}^3$ with frequent exceedances to the 24-hour NAAQS. Their analysis using Chemical Mass Balance indicated that wood smoke from residential combustion was the major source of PM_{2.5} contributing between 60% and 80% of the measured PM.

Wang and Hopke (2014) also performed a source apportionment study in Fairbanks, Alaska. This analysis shows similar results with wood smoke being the highest contribution (~40%) to PM_{2.5} concentrations, followed by secondary sulfates and gasoline. Wang and Hopke conclude that winter heating is the most important factor affecting the air quality in Fairbanks.

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8.3 A DESCRIPTION OF REGIONAL OZONE AND PM_{2.5} PRECURSOR EMISSIONS

Emissions of ozone precursors from the region surrounding the Liquefaction Facility are summarized in **Table 8-1** based on the most recent NEI (USEPA 2016) which was compiled for 2011. The NEI is a comprehensive and detailed estimate of air emissions of criteria pollutants, criteria precursors, and hazardous air pollutants from air emissions sources. Among all the emission sectors Kenai Peninsula Borough, the combustion processes related to electrical utilities and other industrial processes are among the largest contributors to NO_x emissions, followed by mobile emissions. The petroleum and related industries are the largest contributors to VOC emissions in the Kenai Peninsula Borough, followed by the VOC emissions from mobile sources. The NO_x emission totals are very similar between the Municipality of Anchorage and the Kenai Peninsula Borough, but the VOC total emissions are about 67% larger in Anchorage. Matanuska-Susitna Borough shows the lowest total emissions of both NO_x and VOC from the three areas around the project.

Table 8-1: Anthropogenic Emissions in the Region Surrounding the Liquefaction Facility

Emission Inventory Sector	Municipality of Anchorage			Kenai Peninsula Borough			Matanuska-Susitna Borough		
	NO _x (TPY)	VOCs (TPY)	Primary PM _{2.5} (TPY)	NO _x (TPY)	VOCs (TPY)	Primary PM _{2.5} (TPY)	NO _x (TPY)	VOCs (TPY)	Primary PM _{2.5} (TPY)
FUEL COMB. ELEC. UTIL.	1,966	14	43	4,098	331	111	--	--	--
FUEL COMB. INDUSTRIAL	236	40	28	4,187	170	116	285	9	5
FUEL COMB. OTHER	843	474	356	238	122	93	172	139	108
PETROLEUM & RELATED INDUSTRIES	0	2	0	464	3,809	11	26	99	1
OTHER INDUSTRIAL PROCESSES	--	62	122	--	3	32	--	3	32
SOLVENT UTILIZATION	--	2,000	0	--	353	--	--	552	--
STORAGE & TRANSPORT	2	1,629	0	--	565	--	--	433	--
WASTE DISPOSAL & RECYCLING	13	9	1	15	28	82	14	25	81
HIGHWAY VEHICLES	5,158	3,263	184	1,688	1,148	64	1,972	1,485	79
OFF-HIGHWAY	4,057	6,521	312	1,853	1,887	131	616	1,692	68
MISCELLANEOUS	22	413	870	13	207	1,465	3	56	1,471
Total	12,298	14,428	1,916	12,556	8,622	2,105	3,088	4,494	1,844

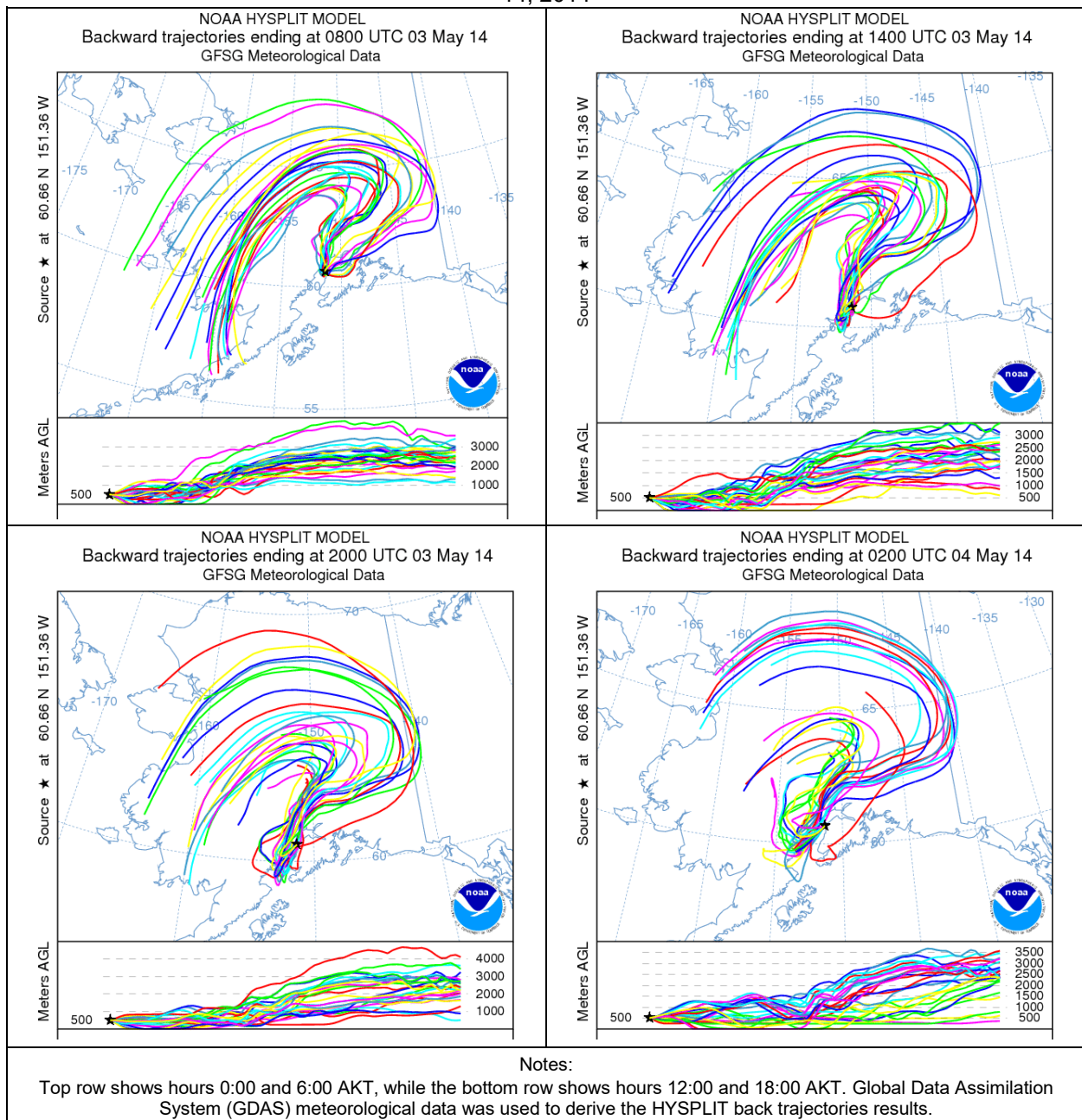
Notes:

Data based on USEPA's 2011 NEI available at
<https://www.epa.gov/air-emissions-inventories/2011-national-emissions-inventory-nei-data>

The table also presents the level of primary PM_{2.5} emissions associated to different sectors on the three counties. In general, the largest source of PM_{2.5} on the Kenai Peninsula is the combined contribution of multiple sources. The PM_{2.5} total among all the areas is very similar.

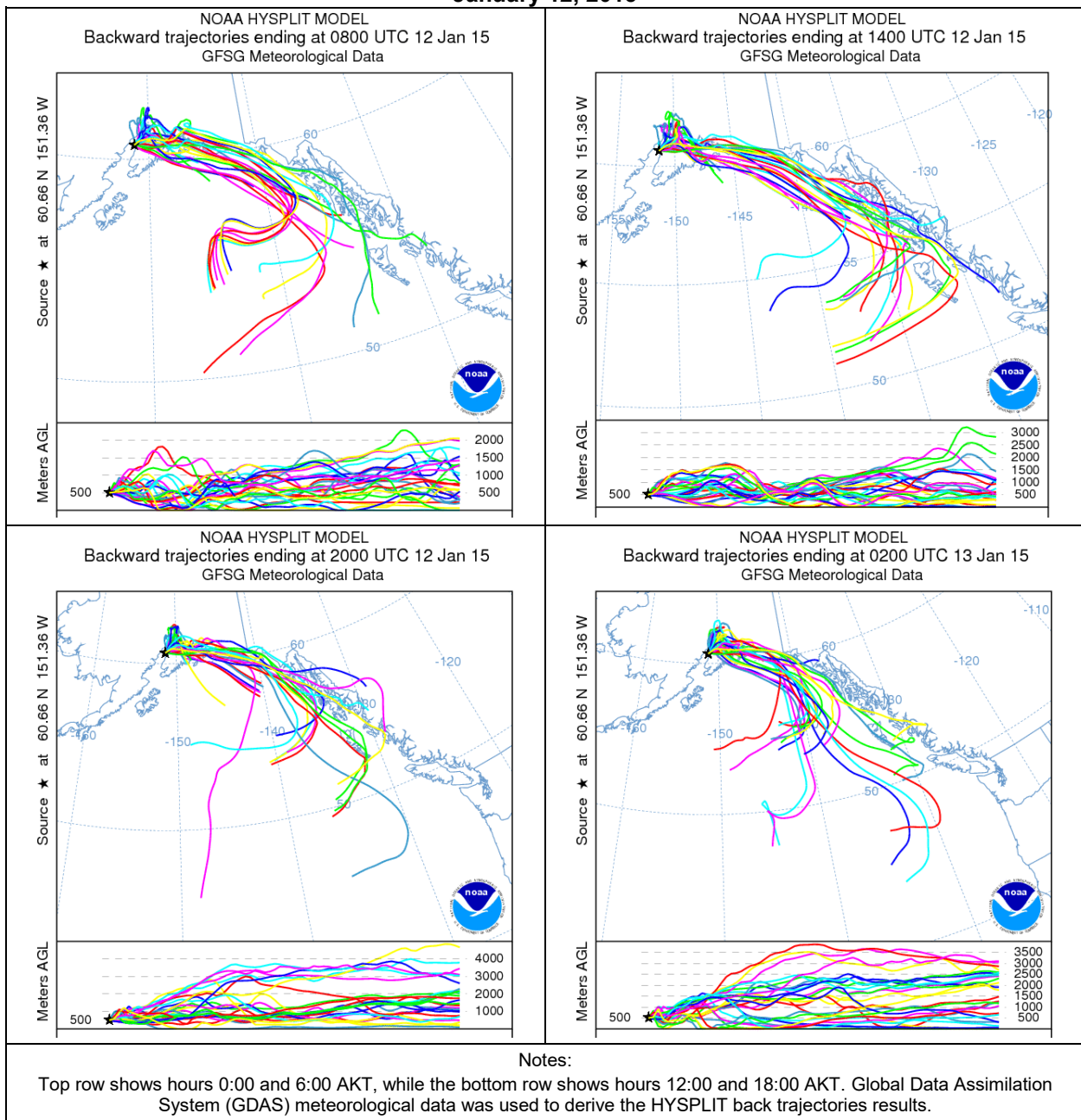
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Figure 8-1: 72-Hour Back trajectories Arriving at the Project Location n at (60.664 N, 151.362 W) May 14, 2014



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Figure 8-2: 72-Hour Back Trajectories Arriving at the Project Location at (60.66 4N, 151.362 W)
January 12, 2015



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8.4 OZONE AND PM_{2.5} ASSESSMENT

Currently, there is insufficient guidance to assess both ozone and PM_{2.5} impacts for this project. The most recent guidance is the “Proposed Approach for Demonstrating Ozone PSD Compliance” (USEPA 2015c) (referred to hereafter as the “Guidance”), which is currently a proposed approach that has not been formally accepted. In this current stage of uncertainty regarding ozone assessment, the following section describes a variety of approaches to understand potential project impacts to existing ambient ozone. From this analysis it is clear that regional ozone concentrations are low, well below the NAAQS/AAQS. The small increase in regional precursor emissions that occur as a result of the project will have a negligible effect on existing ozone and PM_{2.5} concentrations and therefore, regional pollution levels will still remain well below the NAAQS/AAQS.

8.4.1 Regional Modeling

8.4.1.1 Overview of PGM models

Photochemical grid models (PGM) describe atmospheric concentrations in an array of fixed computational grid cells; PGMs are also called Eulerian models. Eulerian models are formulated to solve the pollutant continuity equation, where the pollutants concentrations enter and leave each of the modeling cells species concentrations are estimates as function of space and time. The continuity equation is numerically solved and calculates the changes to the concentrations by the following major processes: advection, turbulent and molecular diffusion, emissions, chemistry and removal (wet and dry). The two state-of-the-science grid models currently used are USEPA’s CMAQ and RAMBOLL ENVIRON’s CAMx.

The USEPA Community Multiscale Air Quality (CMAQ) modeling system is designed for applications ranging from regulatory and policy analysis to understanding the complex interactions of atmospheric chemistry and physics. It is a three-dimensional Eulerian atmospheric chemistry and transport modeling system that simulates ozone, particulate matter (PM), toxic airborne pollutants, visibility, and acidic and nutrient pollutant species throughout the troposphere. Designed as a “one-atmosphere” model, CMAQ can address the complex couplings among several air quality issues simultaneously across spatial scales ranging from local to hemispheric.

The Comprehensive Air Quality Model with Extensions (CAMx) modeling system is a publicly available multi-scale photochemical/aerosol grid modeling system developed and maintained by RAMBOLL ENVIRON (2014). CAMx was developed with new codes during the late 1990s using modern and modular coding practices. This has made the model an ideal platform to treat a variety of air quality issues including ozone, condensable PM, visibility, and acid deposition. The flexible CAMx framework also makes it a convenient and robust host model for the implementation of a variety of mass balance and sensitivity analysis techniques.

A number of studies have been performed since 2008 using both CMAQ and CAMx to estimate the impacts on ozone and PM_{2.5} from single source emissions and also other types of applications. Both models are capable of providing a more realistic chemical and physical environment to evaluate these impacts. These studies show that PGMs are appropriate to establish the impacts from secondary formed pollutants for single sources but also from a vast array of emissions. One recent analysis presented by Baker et al. (2016) provides a more robust range of impacts covering a diverse set of sources, chemical environments and time scales. Baker et al. used CAMx to simulate the evolution of 24 hypothetical sources added to a baseline and evaluated the corresponding perturbation to ozone and PM_{2.5} concentrations. The analysis contributes more information about the downwind effects of single sources, but concludes that further investigation would be needed to fully assess the variability in single source impacts from a range of chemical and physical conditions. Also the analysis performed by Baker et al. focuses exclusively on the

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potential impacts in the continental U.S and a similar effort would be important to establish impacts in regions like Alaska; however this study serves as an important point of reference.

8.4.1.2 PGM Model limitations

Although PGMs can evaluate the impacts of secondary formed pollutants, there are several factors that limit their applications. For instance depending on the spatial resolution of the modeling grid cells, the plumes from the sources could get immediately diffused through the cell and this could impact ozone peak impacts and their spatial distribution. Also there are known limitations and uncertainties in the performance of these models, which require additionally analysis to characterize the potential biases of the pollutants predictions. PGMs usually require adequate modeling platforms and inputs (emissions and meteorology) which could be costly to develop if none exist in the area or region of interest. Also PGM simulations are computationally intensive and require significant amounts of time to complete depending on the application. Finally depending on the magnitude of emissions, estimating the ozone and PM_{2.5} impacts from an individual source may not be appropriate for a PGM application. Also, neither CAMx nor CMAQ include any of the halogen chemistry resulting in ozone depletion events in polar regions previously described.

8.4.2 Analysis of the Contribution of Liquefaction Facility Emissions

8.4.2.1 Liquefaction Facility Emissions

The total potential Liquefaction Facility project emissions of ozone precursors from stationary sources would be approximately 1,600 tons per year (TPY) of NO_x and 330 TPY of VOC. The potential Liquefaction Facility emissions would represent approximately 13% of the total NO_x and about 4% of the total VOC emissions in the Kenai Peninsula Borough (**Table 8-1**). These values reflect the potential to contribute to ozone formation by the Liquefaction Facility, but as has been shown in this analysis most of the observed concentrations near the project are more likely to be the result of long range transport.

8.4.2.2 Potential Impacts

Ozone

Determination of ozone and PM_{2.5} impacts due to emissions from single sources is a very active area of research and model development. Information obtained from a PGM is appropriate to consider since they include a representation of the physical and chemical processes undergone by the atmospheric pollutants. Importantly they account for the photochemical reactions that lead to ozone formation. PGMs have been typically used to investigate the impacts from NO_x sources larger than 1,000 TPY. Another consideration is the lack of representative modeling platforms to be used for specific applications and the elaborate and computationally more expensive needs to perform PGM simulations. For this particular project, the direct application of PGM would not be appropriate given that is not expected that the precursor emissions would lead to the formation of ozone and PM_{2.5} concentrations that contribute to any exceedances of the NAAQS/AAQs. This section reviews some of the available PGM applications and shows the approximate peak ozone impacts that would be expected from the Liquefaction Facility based on applying the PGM model based on single source analyzes.

Baker et al. (2016) provide the most comprehensive up-to-date evaluation and application of PGMs for single source impacts on ozone and PM_{2.5}. Baker et al. present a compilation of 8-hour ozone impacts from NO_x emissions as reported in the literature from multiple studies in addition to their own modeling. It should be expected that given the differences among modeling studies and different geographic areas that similar NO_x emissions would not necessarily lead to identical ozone impacts. However, Baker et al. are able to show consistently that single source NO_x emissions less

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than 2,000 TPY will not lead to ozone impacts larger than approximately 3 ppbv as illustrated in **Figure 8-3. Table 8-2** (adapted from Baker et al. 2016 shows the ozone concentrations predicted from studies in which single sources emitted less than 2,000 TPY of NO_x.

Table 8-2 shows that it can be expected that for NO_x sources in the range of 1,000 to 2,000 TPY, the peak ozone impacts estimated by PGM have ranged from 0.9 to 7.5 ppbv. This range of information provides an approximate estimate of the potential ozone impact associated with the emissions from the Liquefaction Facility. Furthermore, Baker et al. found that peak impacts for the sources included in their assessment and from other studies are typically closer than 50 kilometers downwind from the source but rarely in the same grid cell as the source. Based on this information, peak ozone impacts associated with the Liquefaction Facility are unlikely to occur near the neighboring areas of the project and will not result in attainment issues.

PM_{2.5}

PM_{2.5} concentrations are more difficult to evaluate as particulates are formed by multiple chemical species. However Baker et al. investigated the model peak 24-hour PM_{2.5} sulfate and nitrate concentrations response to the emissions of SO₂ and NO_x. Baker et al. found that the 24-hour PM_{2.5} nitrate concentrations would increase between 0.1 and 0.8 µg/m³ when the emissions of a single source range between 0 and 500 TPY. The potential to emit NO_x from the Liquefaction Facility is less than 2,000 TPY. Baker et al. also found that for SO₂ emissions in the range of 500 to 1,000 TPY, would result in sulfate ion 24-hour PM_{2.5} concentrations range between 0 and 2 µg/m³. The potential to emit SO₂ from the Liquefaction Facility is less than 100 TPY. Baker et al. also show that typical impacts for sulfate PM_{2.5} tend to peak at a distance of approximately 10 kilometers (6 miles) from the source with values of 5 to 8 µg/m³ and then rapidly decrease with distance with almost no impacts after 20 or 30 kilometers (12 to 19 miles) from the source. Nitrate impacts are the largest at a distance of about 5 to 10 kilometers (3 to 6 miles) from the source with values of 0.6 to 1.2 µg/m³ and decrease with distance but impacts could be as large as 0.2 µg/m³ at a distance of 100 kilometers (62 miles) from the source.

Figure 8-3: Relationship Between the Change in Daily Maximum 8-Hour Average O₃ and Change in NO_x Precursor Emissions (TPY) (Baker et al. 2016)

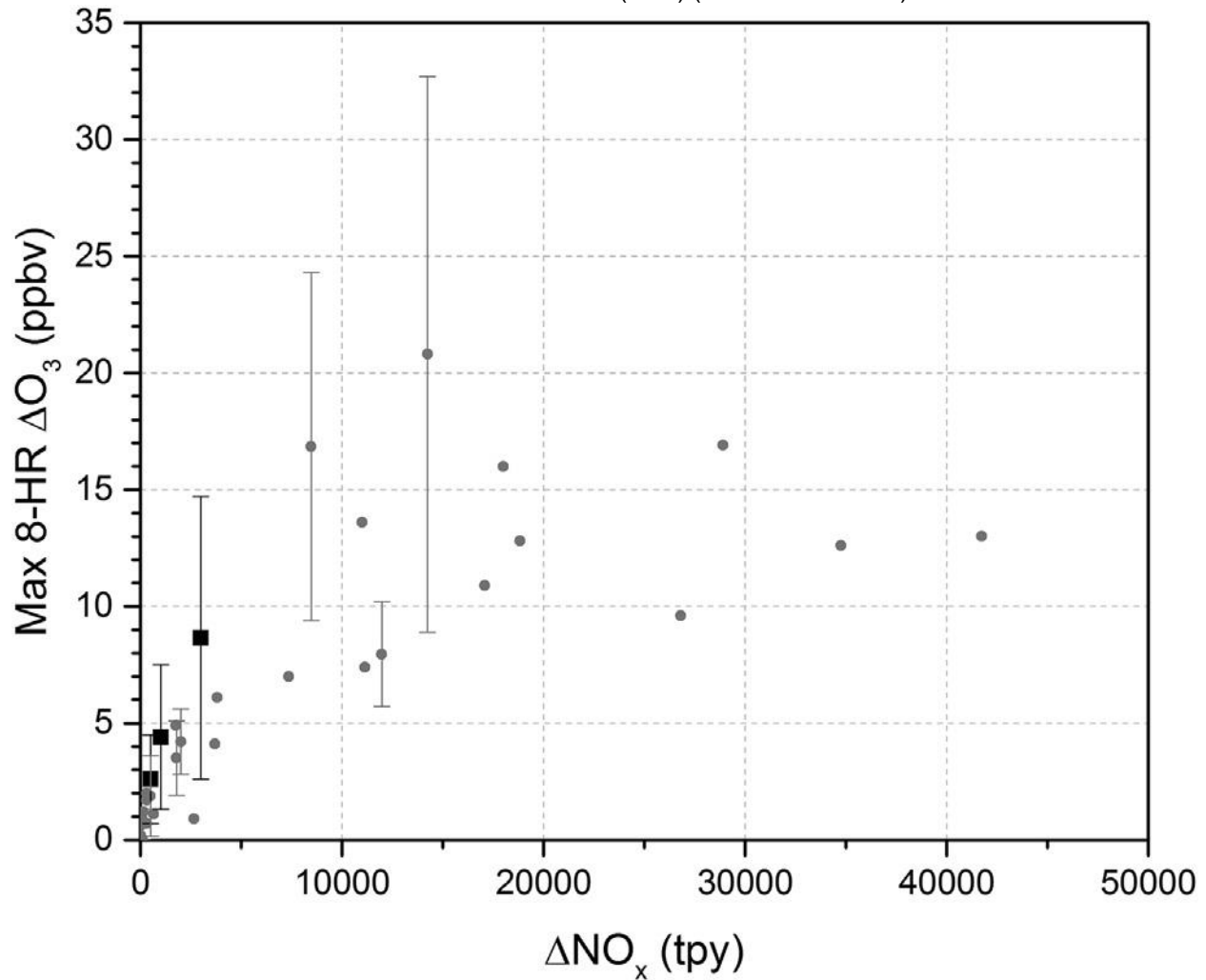


Table 8-2: Compilation of 8-Hour Ozone Impacts (ppbv) from NO_x Emissions (TPY) Reported in Literature (Baker et al. 2016)

Reference	Location	Time Period Modeled	Year Modeled	Type of Source	Method Used	Model Resolution (km)	Stack Height (m)	Annual NO _x Emissions (TPY)	8-hr O ₃ delta (ppbv)
ENVIRON, 2005	Houston, TX	Summer episodes	1999	Single EGU	CAMx brute force	4	Not known	2,665	0.9
Castell et al., 2010	Spain	Summer episodes	2003 & 2004	Single EGU	CAMx brute force	2	65	1,789	1.9-5.1
ENVIRON, 2012a	Utah and Colorado	Full year	2006	Single EGU	CAMx APCA	12	65.5	1,751	4.9
This work	Eastern US	Full year	2011	Hypothetical Source	CAMx OSAT	12	1 and 90	1,000	1.3-7.5
Kelly et al., 2015	California	Summer and winter episodes	2007	Hypothetical Source	CMAQ brute force & DDM	4	90	2,000	2.8-5.6

Notes:

EGU: Electric Generating Units

APCA: CAMx Anthropogenic Precursor Culpability Assessment

OSAT: CAMx Ozone Source Apportionment Technology

DDM: Decoupled Direct Method

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8.5 SUMMARY OF LIQUEFACTION FACILITY OZONE AND SECONDARY PM_{2.5} IMPACTS

This analysis reviewed the processes involved in the formation and loss of ozone and secondary PM_{2.5}. This information is presented to help with the understanding of these processes in general but also in relation to the specific characteristics of the sub-arctic atmosphere. A review of available monitoring data near the project area showed that neither ozone nor PM_{2.5} current concentrations are or have been in exceedance of the NAAQS/AAQS despite continual development in the region. Furthermore, back trajectory analysis for selected episodes identified from the monitoring data suggests that observed concentrations could be at least in part the result of pollution transported from Anchorage and midlatitude regions.

Using available tools, a conservative quantification of the potential regional impact of the Liquefaction Facility in both ozone and PM_{2.5} was developed. The information provided in this analysis is very conservative as it relies on photochemical modeling performed for the continental U.S, which does not account for the chemical complexities (halogen chemistry), the seasonal pattern (photochemical shutdown in the winter), and the global boundary influences (long range transport contribution to pollution from Asia and Europe) known to occur in Alaska.

The analysis presented indicates that emissions from the Liquefaction Facility would at most lead to ozone increments of about 3 ppbv. Notice that this increase is not additive, otherwise the cumulative effect of existing sources would have already affected the monitoring record. Also, the location of peak impact is likely to be variable in space and time. This maximum increase of 3 ppbv in a region where ozone design values currently range around 0.045 ppmv would not lead to nonattainment issues in the region.

For PM_{2.5}, the analysis presented indicates that emissions from the Liquefaction Facility would at most lead to nitrate increments of about 1 µg/m³ and sulfate increments of less than 2 µg/m³ for the 24-hour averaging period. These would be the estimated PM_{2.5} impacts that are not expected to occur near the source, but downwind as the result of secondary formation. Just as with ozone this increase is not additive and the location of peak impact likely to be variable in space and time. This maximum increase of less than 3 µg/m³ in a region where PM_{2.5} concentrations range around 10 µg/m³ would not lead to nonattainment issues in the region. Furthermore, the formation of ammonium sulfate and nitrate would be significantly limited by the availability of ammonia as previously discussed.

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9.0 ACRONYMS AND TERMS

AAAQS	Alaska Ambient Air Quality Standards
ADEC	Alaska Department of Environmental Conservation
AERMAP	AERMOD terrain preprocessor
AERMET	AERMOD meteorological processor
AERMOD	American Meteorological Society/USEPA Regulatory Model
AERSCREEN	Screening-level air quality model base on AERMOD
AKT	Alaska Time
APCA	Anthropogenic Precursor Culpability Assessment
AQRVs	Air Quality Related Values
ARM	Ambient Ratio Method
ARM2	Ambient Ratio Method 2
BART	Best Available Retrofit Technology
BMP	Best Management Practices
BOG	Boiloff gas
BPIPPRM	Building Profile Input Program
CAA	Clean Air Act
CALMET	CALPUFF meteorology preprocessor
CALPOST	CALPUFF post-processor
CALPUFF	Gaussian puff dispersion model used for far-field modeling
CAMx	Comprehensive Air Quality Model with Extensions
CMAQ	Community Multiscale Air Quality model
CO	Carbon Monoxide
COP	ConocoPhillips Company
DATs	Deposition Analysis Thresholds
DDM	Decoupled Direct Method
EMALL	ExxonMobil Alaska LNG LLC
EGU	Electric Generating Unit
FERC	Federal Energy Regulatory Commission
FLAG	Federal Land Manager's Air Quality related Values Work Group
FLMs	Federal Land Managers
GDAS	Global Data Assimilation System
GEP	Good Engineering Practice
GTP	Gas Treatment Plant
GVEA	Golden Valley Electric Association
HEA	Homer Electric Association
HNO ₃	Nitric Acid
HRSG	Heat Recovery Steam Generator
HYSPLIT	Hybrid Single Particle Lagrangian Integrated Trajectory Model
IC	Internal Combustion
ISCST3	Predecessor of AERMOD
KPL	Tesoro Kenai Pipe Line Marine Loading Terminal
LNG	Liquefied Natural Gas
LNGC	Liquefied Natural Gas Carrier
LP	Low pressure
LPG	Liquefied Propane Gas
MM5	NCAR Mesoscale Model
MPTER	Multiple point source Gaussian dispersion model with terrain
N	Nitrogen
NAAQS	National Ambient Air Quality Standards
NAD83	North American Datum 1983

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NCSLs	National Conservation System Lands
NDBC	National Data Buoy Center
NED	National Elevation Dataset
NEI	National Emissions Inventory
NEPA	National Environmental Policy Act
NGA	Natural Gas Act
NO ₂	Nitrogen Dioxide
NOAA	National Oceanic and Atmospheric Administration
NO _x	Nitrogen Oxides
NP	National Park
NSR	New Source Review
NWR	National Wildlife Refuge
NWS	National Weather Service
O ₃	Ozone
ODE	Ozone Depletion Event
OH	Hydroxyl
OLM	Ozone Limiting Method
OSAT	Ozone Source Apportionment Technology
Pb	Lead
PBU	Prudhoe Bay Unit
PGM	Photochemical Grid Model
PLUVUE II	Plume visibility model used for near-field visual impact modeling
PM	Particulate Matter
PM ₁₀	Particulate matter having an aerodynamic diameter of 10 microns or less
PM _{2.5}	Particulate matter having an aerodynamic diameter of 2.5 microns or less
POSTUTIL	CALPUFF Post-Processor
ppbv	Parts per billion by volume
ppmv	Parts per million by volume
Project	Alaska LNG Project
PSD	Prevention of Significant Deterioration
PTU	Point Thomson Unit
PVMRM	Plume Volume Molar Ratio Method
Report	FERC Air Quality Modeling Report
RFD	Reasonable Foreseeable Development
RICE	Reciprocating Internal Combustion Engine
RML	Regional Modeling Center
S	Sulfur
SDM	Shoreline Dispersion Model
SFM	Shoreline Fumigation Model
SIP	State Implementation Plan
SO ₂	Sulfur Dioxide
TIBL	Thermal Internal Boundary Layer
TPY	Tons per year
USDOI	US Department of the Interior
USEPA	U.S. Environmental Protection Agency
UTM	Universal Transverse Mercator
VISCREEN	A screening model used for near-field visual impact modeling
WRAP	Western Regional Air Partnership

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8.3.1 Back Trajectories Analysis on Days with Elevated Ozone Concentrations

To better characterize periods of elevated ozone concentrations, it is helpful to understand the history of these air masses. Back trajectories derived using the HYSPLIT model (NOAA: <http://www.arl.noaa.gov/hysplit>) were used to further analyze periods with elevated ozone concentrations near the project area as indicated by available monitoring data. **Figure 8-1** shows back trajectories displaying a 72-hour time period ending at hours 0:00, 6:00, 12:00 and 18:00 AKT for May 3, 2014 when the monitor located at the Agrium facility indicates 8-hour average daily maximum concentrations could be as high as 0.0609 ppmv. The figures show that for most of the day, air masses are transported to the Liquefaction Facility area from the north. These trajectories are important as it seems to suggest that for this particular event a significant contribution of the ozone concentrations observed at Agrium could be transported downwind from Anchorage. The spatial extent of the trajectories suggests that, for the most part, the observed concentrations are the result of transported ozone into the region more than locally formed ozone.

8.3.2 Back Trajectories Analysis on Days with Elevated PM_{2.5} Concentrations

To better characterize periods of elevated PM_{2.5} concentrations, it was also determined to understand the history of these air masses. Back trajectories derived using the HYSPLIT model (NOAA: <http://www.arl.noaa.gov/hysplit>) were used to further analyze periods with elevated PM_{2.5} concentrations near the project area as indicated by available monitoring data. **Figure 8-2** shows back trajectories displaying a 72-hour time period ending at hours 0:00, 6:00, 12:00 and 18:00 AKT for January 12, 2015 when the Butte monitor (located 158 kilometers away from the project) indicates PM_{2.5} concentrations could be as high as 61.5 µg/m³. The figures show that for most of the day, air masses are transported to the Liquefaction Facility area from the north passing by Anchorage. The figures also illustrate the prevalent travel of air masses along the western coast of Canada, potentially transporting particulates from these regions to the project area. The spatial extent of the trajectories suggests that, for the most part, the observed concentrations are the result of transported particles into the region more than from local emissions.

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11.0 APPENDICES

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APPENDIX A – LIQUEFACTION FACILITY AIR EMISSIONS INVENTORY



**EMISSIONS CALCULATION REPORT FOR THE
ALASKA LNG LIQUEFACTION FACILITY**

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APPENDIX A

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1.0 OBJECTIVE OF EMISSIONS CALCULATION REPORT

The Alaska Gasline Development Corporation, BP Alaska LNG LLC, ConocoPhillips Alaska LNG Company, and ExxonMobil Alaska LNG LLC (Applicants) plan to construct one integrated liquefied natural gas (LNG) Alaska LNG Project (Project). The project contains two separate facilities, the Gas Treatment Plant (GTP) and the Liquefaction Facility.

The purpose of this Emissions Calculation Report (Report) is to present the methodologies that were used to calculate the air pollutant emissions from sources at the Liquefaction Facility. Quantitative emissions data is needed to demonstrate that these facilities would adhere to the applicable Clean Air Act (CAA) requirements as administered by the Environmental Protection Agency (USEPA) and the Alaska Department of Environmental Conservation (ADEC), and to support the assessment of air quality impacts for the Federal Energy Regulatory Commission (FERC) application and the associated National Environmental Policy Act (NEPA) process. Specifically presented are the methods proposed for developing emissions data to support the following analyses:

- Determining applicable permitting requirements triggered by the proposed facilities
- Assessment of the facilities' air quality impacts for the project's FERC application and in the subsequent NEPA analyses
- Dispersion modeling to evaluate the project's compliance with applicable state and federal ambient air quality standards and related thresholds
- Additional modeling to evaluate the facility's impacts to air quality-related values (AQRVs), including visibility, acid deposition, and impacts to soils, flora and fauna

This document explains the emission calculations located in the sections at the end of this report. The explanations located in this report provide a basis for the values and methods used within the calculations, both items should be reviewed simultaneously. The facility emission calculations are represented by the document sections prefixed with EC (Emission Calculation). The marine terminal emission calculations are represented by the document sections prefixed with MEC (Marine Emission Calculation). The tables located within this report reference both the summary tables and the individual equipment calculation pages.

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2.0 DESCRIPTION OF THE LIQUEFACTION FACILITY

The Liquefaction Facility, which would consist of the LNG Plant and the Marine Terminal, would receive North Slope natural gas via the Project Mainline, liquefy the gas, and store the liquefied natural gas (LNG) on-site until the LNG would ship from the adjacent Marine Terminal by LNG carrier vessels.

The LNG Plant is designed to produce 20 million metric tons (tonnes) per annum of liquefied natural gas, and includes liquefaction, processing and storage facilities, and necessary utility systems. It would include three identical trains comprised of compression and refrigeration equipment to liquefy the compressed natural gas from the GTP to salable LNG. Major equipment at the facility would include gas-fired turbines, liquid fuel-fired reciprocating internal combustion engines, gas-fired auxiliary equipment, and flares.

The Marine Terminal would include the trestle(s), flare, piping, and berthing facilities associated with LNG carrier loading and berthing. The carrier vessels that would call at the Marine Terminal would be equipped with either diesel engines or steam systems for the main propulsion and auxiliary equipment to assist in the loading of the LNG into onboard compartments for transit. They would be assisted in berthing, loading and unberthing operations by tugboats and other support vessels.

The fuel gas to be used at the Liquefaction Facility was assumed to have 16 ppmv sulfur in accordance with the pipeline specification of 1 grain sulfur/100 standard cubic feet of gas.

Table 2-1 lists the major emissions emitting equipment at the Liquefaction Facility. Mobile and non-road equipment associated with facility operations and the methods used to quantify the associated emissions are described in **Section 9.0** of this Report. **Table 2-2** shows ambient temperature data for Nikiski that was used in developing emissions data for equipment of the Liquefaction Facility (see **Sections 4.0** through **8.0**).

Ambient temperature data was obtained from the Cooperative Observer Network (COOP) Summaries for Alaska from the Western Regional Climate Center (WRCC 2006). Regional temperatures are based on measurements from Nikiski Terminal (1967-1978), and Kenai FAA Airport (1949-2006). Temperatures at these locations were assumed to be representative for the Liquefaction Facility location. The COOP information (WRCC 2006) from all locations shows annual average temperatures close to 40°F; the average at Nikiski Terminal is 42.2°F, and the Kenai Airport mean value is 42.2°F. The value of 40°F was selected after rounding to one significant digit. The listed lowest and highest ambient temperatures were selected to represent the maximum and minimum probable temperatures during normal operation at the site, rather than extreme temperature values that have rarely been recorded. A representative low ambient temperature of -30°F was selected based on the very small reasonably foreseeable probability of the ambient temperature being below -30°F for any extended period of time. The regional temperature data indicates one instance of a temperature below -30°F in the past 15 years. Similarly, 70°F, was selected, for the representative highest ambient temperature, based on a review of the regional temperature data showing that ambient values higher than 70°F have not occurred in almost 45 years.

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Table 2-1 Liquefaction Facility Emitting Equipment Type and Count

Equipment Type	Facility Count
Compressor Turbines	6
Power Generation Turbines	4
Reciprocating Internal Combustion Engines (Emergency/Non-Emergency)	2
Fuel Gas Heaters/Boilers	0
Flares (Including Thermal Oxidizer)	8
Marine Equipment (Site Specific Vessels, excluding LNG carrier vessels)	4

Table 2-2 Ambient Temperatures Used for Liquefaction Facility Calculations

	Temperature (°F)
Lowest Ambient	-30
Highest Ambient	70
Annual Average Ambient	40

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3.0 DESCRIPTION OF EMISSIONS DATA NEEDS

3.1 PREVENTION OF SIGNIFICANT DETERIORATION (PSD) APPLICABILITY AND REVIEW

The federal PSD permitting program applies to major new stationary sources and major modifications of existing sources that are proposed to be located in areas that are in compliance with the National Ambient Air Quality Standards (NAAQS). A source is “major” for a given pollutant if the maximum expected facility-wide emissions of that pollutant from a new facility will exceed 250 tons per year (tpy), or 100 tpy for 28 named facility categories. New sources with potential emissions in excess of the 100/250 thresholds are subject to PSD review. If a facility is major for at least one pollutant, then other pollutants emitted in amounts above their respective Significant Emission Rates (SERs) are also subject to the PSD process. The SERs are 40 tpy for NO_x, SO_x, and VOCs, 15 tpy for PM₁₀, and 10 tpy for PM_{2.5}.

The Project would be required to apply for PSD permit reviews for the Liquefaction Facility at Nikiski (see **Section 2.0**). Maximum possible annual emissions for all criteria pollutants were calculated for individual equipment and then summed to provide facility-wide emissions for comparison with the major source thresholds and applicable Significant Emission Rate (SER) limits.

Assumed maximum hourly emission rates and the maximum foreseeable facility operating hours per year were used to calculate maximum annual emissions for these applicability determinations. The calculated annual pollutant rates from each stationary source should be conservative enough that they would never be exceeded during normal operations. Emission factors derived from vendors, source tests for comparable equipment or from standard references, such as the USEPA’s *AP-42 Compilation of Air Pollutant Emission Factors* (USEPA 2009), may be used for certain pollutants if suitable vendor data are not available.

3.2 FEDERAL ENVIRONMENTAL REGULATORY COMMISSION (FERC) IMPACT ASSESSMENT

The Federal Energy Regulatory Commission (FERC) requires a full assessment of all emissions sources associated with the proposed facilities, including sources that are not normally included in the PSD review, such as mobile sources and construction emissions¹.

Inasmuch as the focus of the FERC environmental review is on assessing a proposed Project’s anticipated actual impacts, it might be assumed that only expected actual emissions data would be required. However, FERC guidance for the preparation of Resource Report No. 9, *Air and Noise Quality*, also requires evidence of a Project’s ability to obtain required permits. In the case of the Project, this includes showing that the Liquefaction Facility can satisfy the requirements of the PSD review, which mostly evaluates impacts for maximum potential facility emissions. Thus, the emissions data required for preparation of the Project FERC submittal will rely primarily on the same assumptions as that for PSD permitting.

Assumed maximum emission rates and the maximum foreseeable facility operating hours per year were used to calculate maximum annual emissions for the FERC submittal. The calculated annual pollutant rates from each stationary source should be conservative enough that they would never be exceeded during normal operations. Emission factors derived from source tests for comparable equipment or from standard references, such as the USEPA’s *AP-42 Compilation of Air Pollutant Emission Factors* (USEPA 2009), may be used if suitable vendor data are not available.

¹ The development of construction emissions estimates for the Project is not addressed in this Report.

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Emission rates required for the dispersion modeling analyses presented in the Project submittals to FERC were calculated using the same methodology as described for PSD modeling in the next section.

3.3 PSD DISPERSION MODELING

Under the PSD program, a proposed new major stationary source or major modification must complete a series of air quality impact analyses that includes a comprehensive, cumulative air quality impact analysis to demonstrate that the source's emissions will not cause or contribute to a modeled violation of any NAAQS. This means the applicant will need to model its own source's emissions, as well as those from other existing facilities in the area near the proposed Project facilities, to show compliance with the NAAQS and PSD increments.

The modeling analyses described above is required to evaluate maximum potential impacts for comparison with the NAAQS and PSD increment thresholds. In general, this means that the corresponding modeling analyses must use maximum emission rates for short and long-term averaging times corresponding to these ambient criteria. However, for some types of equipment, most notably gas-fired turbines, pollutant emissions vary for different loads and ambient temperature conditions. For these sources, peak impacts may be predicted to occur at other than peak load operations.

Emissions rates to support the PSD modeling analyses were derived from equipment vendor data, where possible. Such data may be available from manufacturers of turbines, reciprocating engines and boilers/heaters, but may not be forthcoming for flares. Where necessary, source test data from comparable equipment or emission factors from established reference compilations, like USEPA's *AP-42 Compilation of Air Pollutant Emission Factors* (USEPA 2009) were used.

3.4 AIR QUALITY RELATED VALUES (AQRV) MODELING (EVALUATING IMPACTS TO VISIBILITY AND DEPOSITION)

Emission rates to support the AQRV modeling analysis for the new facilities were based on the same methodology as those used in the PSD dispersion modeling assessment. The assumed maximum hourly emission rates and the maximum foreseeable facility operating hours per year were used to calculate maximum annual emissions for the AQRV Analysis. There is an additional requirement to speciate the particulate matter for these analyses into the filterable or elemental carbon (EC) portion, as well as the condensable or secondary organic aerosols (SOA). The PM emissions for each type of equipment were speciated based on the USEPA's *AP-42 Compilation of Air Pollutant Emission Factors* (USEPA 2009). The calculated PM₁₀ and PM_{2.5} rates from each stationary source should be conservative enough that they would never be exceeded during normal operations.

Visibility modeling is based on the maximum 24-hour NO_x, SO_x and PM emission rates from the proposed new facility of interest. To ensure that the resulting impacts are conservative, it is common for these simulations to assume 24 consecutive hours of operation at the maximum possible hourly emission rates for these pollutants. The deposition modeling is based on reasonably foreseeable annual NO_x and SO_x emission rates from the proposed facility.

The impacts to the region's air quality and AQRVs in Class I PSD areas and sensitive Class II areas were developed using the actual emissions from the existing sources, as provided by ADEC. These actual emissions data on existing facilities were augmented with maximum allowable emissions for reasonably foreseeable future sources that are currently undergoing permitting or construction in the areas potentially impacted by emissions of the Project's Liquefaction Facility.

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4.0 DEVELOPMENT OF EMISSIONS AND MODELED STACK PARAMETERS: COMPRESSION TURBINES

4.1 OPERATIONS DESCRIPTION

The compression turbines at the Liquefaction Facility would be arranged with two turbines per train (six turbines total), to compress the refrigerant used to cool the natural gas into liquefied natural gas. The compressors would be located upstream of the refrigerant condensers and would compress the heated refrigerant gas returning from the cross exchangers used to cool the natural gas. The production of LNG would be relatively constant and require a continuous supply of refrigerant. This would require the compressor turbines to operate near 100% continuously with little variation.

4.2 EMISSIONS DATA SOURCES

The turbine vendor provided performance estimates (fuel usage, exhaust gas properties) and emission concentration estimates for certain pollutants in the exhaust for the compression turbines currently proposed for the Liquefaction Facility. See **Section 2.0** and **Table 2-2** for a discussion on selection of a representative ambient temperature range at the Liquefaction Facility site. The vendor created the operating and emissions profiles based on the design specifications of the fuel gas to be utilized at the Liquefaction facility, as well as the ambient temperatures and typical ambient pressure at the proposed facility location.

Table 4-1 lists the sources of the emission factors that were used to calculate turbine emissions, including a mix of vendor estimates and factors from public sources.

Table 4-1 Data Sources for Liquefaction Facility Compression Turbines Emissions Estimation

Pollutant	Data Source Description
NO _x	Vendor Data
CO	Vendor Data
VOC	AP-42 equipment emission factors, Section 3.1 (USEPA 2009)
PM ₁₀ ¹	AP-42 equipment emission factors, Section 3.1 (USEPA 2009)
PM _{2.5}	Assumed same value as PM ₁₀ for the most conservative estimate
SO ₂	Mass balance assuming all sulfur in the fuel becomes SO ₂ (H ₂ SO ₄ emissions included in SO ₂)
Lead ²	Negligible
Total GHG	40 CFR Part 98 Subpart C (USEPA 2011)
Total HAPs	AP-42 equipment emission factors, Section 3.1 (USEPA 2009)
NO ₂ /NO _x Ratio	USEPA Tier 2 Ambient Ratio Method 2 (ARM2), refer to modeling specific Report for more details
Note 1: AP-42 emission factor was assumed to be sufficiently conservative for this equipment so that additional particulate matter resulting from the small percentage of sulfur compounds in the fuel were not added. Note 2: The primary source of lead emissions from combustion sources would be lead additives contained in some fuels that could subsequently be emitted during combustion. Since lead is not an additive to any Liquefaction Facility source fuels, it would only be present at negligible trace levels as a result of engine lubricant constituents or due to engine wear. Therefore, lead emissions are negligible, and the source emissions do not cause or contribute to an exceedance of the lead NAAQS.	

4.3 EMISSION CALCULATION METHODOLOGY FOR DETERMINATION OF POTENTIAL TO EMIT AND MODELING

Information on maximum foreseeable annual emissions was needed to determine the individual equipment and total facility potential to emit (PTE). Calculating the annual tons per year per pollutant was needed for PSD Applicability determination and for FERC Impact Assessment of facility impacts. Additionally, short-term and long-term emissions were calculated for predicting near-field and far-field air quality impacts by means of dispersion modeling. The following sections describe the calculation methods for determining annual ton per year and emissions for other appropriate averaging times as required for modeling.

4.3.1 Potential to Emit for PSD Applicability and FERC Impact Assessment

Annual emission rates to support FERC Impact Assessment were quantified in the same manner used to quantify emissions for comparison to New Source Review PSD Applicability thresholds. Considerations that drove the emission calculations for the compression turbines include the assumed operating load, ambient temperature, and supplemental firing.

Operating Load and Ambient Temperature Selection

Table 4-2 provides the assumed operating hours, as well as the assumed turbine loads and ambient temperatures corresponding to the maximum annual pollutant emission rates. The selected emissions and operating conditions provided a conservative estimate of the compression turbines PTE values for PSD Applicability and FERC Impact Assessment because of the following:

- Operation at maximum load was assumed for a full year, without any variations that would typically result in lower emissions.
- Use of emission rates corresponding to the annual average ambient temperature provided the best annual estimate across all operating temperatures that would affect the turbine operation and therefore the emissions.

Table 4-2 Assumed Liquefaction Facility Compression Turbine Annual Operations

Pollutant	Annual Operating Hours	Selected Load	Selected Ambient Temperature
NO _x	Continuous Full-Time Operation (8,760 hours)	Maximum Operating Load (100%)	Annual Average Temperature (40°F)
CO			
VOC			
PM ₁₀			
PM _{2.5}			
SO ₂			
Total GHG			
Total HAPs			

Supplemental Firing Considerations Annual Emissions Calculations

Supplemental firing was not utilized in the design of the Liquefaction Facility compression turbines.

Final Calculated Annual Emissions

The annual emissions calculated for the compression turbines to be included in the facility's PTE summary are shown in **Table 4-3**.

Table 4-3 Liquefaction Facility Compression Turbines PTE Summary

Pollutant		Compressor Turbine (per turbine)	Reference to Calculation
NO _x	ton/year	157	Sections EC-1 and EC-4
CO	ton/year	265	
VOC	ton/year	10.9	
PM ₁₀	ton/year	34.3	
PM _{2.5}	ton/year	34.3	
SO ₂	ton/year	12.2	
GHG	tonnes/year	517,860	
HAPs	ton/year	5.01	

4.3.2 Criteria Pollutant Modeling

Conservative estimates of maximum short-term and long-term emissions were needed to support required dispersion modeling for evaluation of Liquefaction Facility impacts to air quality. Additionally, representative stack parameters (exhaust temperature and velocity) accompanying these emission rates were needed to represent the individual facility sources within the air dispersion model. The long-term annual emissions were calculated using the same methodology used to determine the PTE emissions, as previously described.

Operating Load and Ambient Temperature Selection

Table 4-4 shows the operational loads and ambient temperatures used to determine the compression turbine emission rates and stack parameters that were assumed in the dispersion modeling to evaluate short-term criteria pollutant impacts (averaging times of 1 to 24 hours). The following conventions were used to provide this information to support the modeling analyses:

- The exhaust velocity used was the minimum velocity across the range of turbine loads and ambient temperatures, this corresponded to operation at the maximum ambient temperature.
- The exhaust temperature used was the minimum temperature across the range of turbine loads and ambient temperatures, this corresponded to operation at the minimum ambient temperature.
- Maximum impacts were predicted conservatively by the model using the maximum emission rates in combination with the minimum exhaust velocities and exhaust temperatures.

Table 4-5 provides similar information relating to the emission rates and stack parameters assumed for modeling long-term (i.e., annual average) turbine impacts.

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Table 4-4 Short-Term Modeling Parameters for Liquefaction Facility Compression Turbines

Pollutant	Emission Type	Maximum Emissions		Minimum Exhaust Velocity		Minimum Exhaust Temperature	
		Selected Load	Selected Ambient Temperature	Selected Load	Selected Ambient Temperature	Selected Load	Selected Ambient Temperature
NO _x	1-Hour	Maximum Operating Load (100%)	Minimum Ambient Temperature (-30°F)	Maximum Operating Load (100%)	Maximum Ambient Temperature (70°F)	Maximum Operating Load (100%)	Minimum Ambient Temperature (-30°F)
CO	1-Hour						
	8-Hour						
PM ₁₀	24-Hour						
PM _{2.5}	24-Hour						
SO ₂	1-Hour						
	3-Hour						
	24-Hour						

Table 4-5 Long-Term Modeling Parameters for Liquefaction Facility Compression Turbines

Pollutant	Annual Emissions		Minimum Exhaust Velocity		Minimum Exhaust Temperature	
	Selected Load	Selected Ambient Temperature	Selected Load	Selected Ambient Temperature	Selected Load	Selected Ambient Temperature
NO _x	Maximum Operating Load (100%)	Annual Average Temperature (40°F)	Maximum Operating Load (100%)	Maximum Ambient Temperature (70°F)	Maximum Operating Load (100%)	Minimum Ambient Temperature (-30°F)
CO						
PM ₁₀						
PM _{2.5}						
SO ₂						

Supplemental Firing Considerations Modeling Emissions Calculations

Supplemental firing was not utilized in the design of the Liquefaction Facility compression turbines. Accordingly, no consideration of potential effects of supplemental firing on the emission rates and stack parameters of these turbines were needed.

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Final Calculated Modeling Emissions

The short-term and long-term emissions calculated for the compression turbines to be included in the facility's modeling compliance demonstration are shown in **Table 4-6**.

Table 4-6 Modeling Emissions Summary for Liquefaction Facility Compression Turbine

Pollutant		Compressor Turbine (per turbine)			Reference to Calculation
		Emission (g/s)	Exhaust Temp (°K)	Exhaust Velocity (m/s)	
NO _x	Short-Term	4.74	794	26.21	Sections EC-2 and EC-4
	Long-Term	4.51			
CO	Short-Term	8.02			
PM ₁₀	Short-Term	1.04			
	Long-Term	0.99			
PM _{2.5}	Short-Term	1.04			
	Long-Term	0.99			
SO ₂	Short-Term	0.37			
	Long-Term	0.35			

4.3.3 AQRV Modeling

AQRV modeling is different from criteria pollutant modeling in that it includes additional attention to acid deposition and visibility impacts. Emissions for gaseous pollutants in the AQRV impact assessments were the same as those used in the short-term impact modeling described in **Section 4.3.2**. The short-term particulate matter emissions were speciated for the AQRV analyses as described in the following subsection.

PM Speciation Breakdown

Table 4-7 shows the assumed breakdown and basis for the short-term compression turbine emissions of the PM₁₀ and PM_{2.5} into filterable and condensable fractions, as required for AQRV modeling.

Table 4-7 AQRV PM Speciation for Liquefaction Facility Compression Turbine AQRV

Fuel Type	Fine Particulates from Non-Combustion	Elemental Carbon (% Filterable)		Secondary Organic Aerosols (% Condensable)		Reference
		PM _{2.5}	PM ₁₀	PM _{2.5}	PM ₁₀	
Gas	0	29%	29%	71%	71%	AP-42 Table 3.1-2a (USEPA 2009)

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5.0 DEVELOPMENT OF EMISSIONS AND MODELED STACK PARAMETERS: POWER GENERATION TURBINES

5.1 OPERATIONS DESCRIPTION

The Liquefaction Facility main power generation system would consist of four gas-driven turbines which would create a common power supply to the facility. The power generation turbine load would fluctuate based on the needs of the process trains; the turbine load can range from 60% to 100%. Seasonal load variations would be the most common reason for differences in power generation equipment operation. At the Liquefaction Facility, the air cooler fans in the refrigerant condensers would have a much higher energy demand during the summer months, than in winter, thus requiring a higher power generation turbine output.

The power generation turbines at the Liquefaction Facility would all be equipped with HRSGs for steam production at the facility. The HRSGs would operate by transferring the heat from the hot turbine exhaust gas to water, causing a phase change into steam. The steam would then be used by steam turbines within the facility's power generation plant.

The HRSG would be designed to always accept the full exhaust flow from the power generation turbines. Downstream of the HRSG is an exhaust stack that would be the actual emission point. The HRSG would be designed to transfer the heat duty of the exhaust gas that corresponds to a temperature loss of roughly 600°F to 700°F. The typical outlet exhaust temperature of the power generation turbines would be 1,000°F. The HRSG would reduce the temperature of the exhaust gas at the stack to 341°F and would not cause an increase in pollutant emissions at the turbine stack.

5.2 EMISSIONS DATA SOURCES

The turbine vendor provided performance estimates (fuel usage, exhaust gas properties) and emission concentration estimates for certain pollutants in the exhaust for the power generation turbines currently proposed for the Liquefaction Facility. See **Section 2.0** and **Table 2-2** for a discussion on selection of a representative ambient temperature range at the Liquefaction Facility site. The vendor created the operating and emissions profiles based on the design specifications of the fuel gas to be utilized at the Liquefaction Facility, as well as ambient temperatures and typical ambient pressure for the proposed facility location.

Table 5-1 lists the sources of the emission factors that were used to calculate turbine emissions, including a mix of vendor estimates and factors from public sources.

Table 5-1 Data Sources for Liquefaction Facility Power Generation Turbine Emissions Estimation

Pollutant	Data Source Description
NO _x	Vendor Data
CO	Vendor Data
VOC	AP-42 equipment emission factors, Section 3.1 (USEPA 2009)
PM ₁₀ ¹	AP-42 equipment emission factors, Section 3.1 (USEPA 2009)
PM _{2.5}	Assumed same value as PM ₁₀ for the most conservative estimate
SO ₂	Mass balance assuming all sulfur in the fuel becomes SO ₂ (H ₂ SO ₄ emissions included in SO ₂)
Lead ²	Negligible
Total GHG	40 CFR Part 98 Subpart C (USEPA 2011)
Total HAPs	AP-42 equipment emission factors, Section 3.1 (USEPA 2009)
NO ₂ /NO _x Ratio	USEPA Tier 2 Ambient Ratio Method 2 (ARM2), refer to modeling specific Report for more details

Note 1: AP-42 emission factor was assumed to be sufficiently conservative for this equipment so that additional particulate matter resulting from the small percentage of sulfur compounds in the fuel were not added.

Note 2: The primary source of lead emissions from combustion sources would be lead additives contained in some fuels that could subsequently be emitted during combustion. Since lead is not an additive to any Liquefaction Facility source fuels, it would only be present at negligible trace levels as a result of engine lubricant constituents or due to engine wear. Therefore, lead emissions are negligible, and the source emissions do not cause or contribute to an exceedance of the lead NAAQS.

5.3 EMISSION CALCULATION METHODOLOGY FOR DETERMINATION OF POTENTIAL TO EMIT AND MODELING

Information on maximum foreseeable annual emissions was needed to determine the individual equipment and total facility PTE. Calculating the annual tons per year per pollutant was needed for PSD Applicability and for FERC Impact Assessment of facility impacts. Additionally, short-term and long-term emissions were calculated for predicting near-field and far-field air quality impacts by means of dispersion modeling. The following sections describe the calculation methods for determining annual tons per year and emissions for other appropriate averaging times as required for modeling.

5.3.1 Potential to Emit for PSD Applicability and FERC Impact Assessment

Annual emission rates to support FERC Impact Assessment were estimated in the same manner used to quantify emissions for comparison with New Source Review PSD Applicability thresholds. Considerations that drove the emission calculations for the power generation turbines include operating load and ambient temperature.

Operating Load and Ambient Temperature Selection

Table 5-2 provides the assumed operating hours, as well as the assumed turbine loads and ambient temperatures corresponding to the maximum annual pollutant emission rates. The selected emissions and operating conditions provided a conservative estimate of the power generation turbines PTE for PSD Applicability and FERC Impact Assessment because of the following:

- Operation at maximum load was assumed for a full year without any variations in load, that would typically result in lower emissions.
- Use of the emission rates corresponding to the annual average ambient temperature provided the best annual estimate across all operating temperatures that would affect the turbine operation and therefore the emissions.

Table 5-2 Assumed Liquefaction Facility Power Generation Turbine Annual Operations

Pollutant	Annual Operating Hours	Selected Load	Selected Ambient Temperature
NO _x	Continuous Full-Time Operation (8,760 hours)	Maximum Operating Load (100%)	Annual Average Temperature (40°F)
CO			
VOC			
PM ₁₀			
PM _{2.5}			
SO ₂			
Total GHG			
Total HAPs			

Supplemental Firing Considerations Annual Emissions Calculations

The Liquefaction facility power generation turbines would be equipped with Heat Recovery Steam Generation units; however, a supplemental firing capability was not provided in the design of these turbines and no additional emissions from such activity were need to be accounted for.

Final Calculated Annual Emissions

The annual emissions calculated for the power generation turbines to be included in the facility's PTE summary are shown in **Table 5-3**.

Table 5-3 Liquefaction Facility Power Generation Turbines PTE Summary

Pollutant		Power Generation Turbine (per turbine)	Reference to Calculation
NO _x	ton/year	52.9	Sections EC-1 and EC-4
CO	ton/year	17.9	
VOC	ton/year	3.76	
PM ₁₀	ton/year	11.8	
PM _{2.5}	ton/year	11.8	
SO ₂	ton/year	4.19	
GHG	tonnes/year	178,670	
HAPs	ton/year	1.73	

5.3.2 Criteria Pollutant Modeling

Conservative estimates of maximum short-term and long-term emissions were needed to support required dispersion modeling for evaluation of Liquefaction Facility impacts to air quality. Additionally, representative stack parameters (exhaust temperature and velocity) accompanying these emission rates were needed to represent the individual facility sources within the air dispersion model. The long-term annual emissions were calculated with the same methodology used to determine the PTE emissions, as previously described.

Operating Load and Ambient Temperature Selection

Table 5-4 shows the operational loads and ambient temperatures used to determine the power generation turbine emission rates and stack parameters for dispersion modeling to evaluate short-term impacts (averaging times of 1 to 24 hours). The following conventions were used to provide this information to support the modeling analyses:

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- The exhaust velocity used for modeling was the minimum velocity across the range of turbine loads and ambient temperatures.
- The exhaust temperature was determined by considering the range of temperatures for each turbine load and ambient temperature as well as the exhaust temperature due to operation of the HRSG. An exhaust temperature of 341°F was selected for use in the dispersion modeling because it is the minimum of all temperatures considered as limited by the HRSG.
- Maximum impacts were predicted conservatively by the model by using the maximum emission rates in combination with the minimum exhaust velocities and exhaust temperatures.

Table 5-5 provides similar information relating to the emission rates and stack parameters assumed for modeling long-term (i.e., annual average) turbine impacts.

Table 5-4 Short-Term Modeling Parameters for the Liquefaction Facility Power Generation Turbines

Pollutant	Emission Type	Maximum Emissions		Minimum Exhaust Velocity		Minimum Exhaust Temperature	
		Selected Load	Selected Ambient Temperature	Selected Load	Selected Ambient Temperature	Selected Load	Selected Ambient Temperature
NO _x	1-Hour	Maximum Operating Load (100%)	Minimum Ambient Temperature (-30°F)	Minimum Operating Load (60%)	Maximum Ambient Temperature (70°F)	Constant for all Turbine Loads and Ambient Temperatures (Based on Process Steam Needs, Minimum Exhaust Temperature of 341°F considered)	
CO	1-Hour						
	8-Hour						
PM ₁₀	24-Hour						
PM _{2.5}	24-Hour						
SO ₂	1-Hour						
	3-Hour						
	24-Hour						

Table 5-5 Long-Term Modeling Parameters for the Liquefaction Facility Power Generation Turbines

Pollutant	Annual Emissions		Minimum Exhaust Velocity		Minimum Exhaust Temperature	
	Selected Load	Selected Ambient Temperature	Selected Load	Selected Ambient Temperature	Selected Load	Selected Ambient Temperature
NO _x	Maximum Operating Load (100%)	Annual Average Temperature (40°F)	Minimum Operating Load (60%)	Maximum Ambient Temperature (70°F)	Constant for all Turbine Loads and Ambient Temperatures (Based on Process Steam Needs, Minimum Exhaust Temperature of 341°F considered)	
CO						
PM ₁₀						
PM _{2.5}						
SO ₂						

Supplemental Firing Considerations Modeling Emissions Calculations

The Liquefaction Facility power generation turbines would be equipped with Heat Recovery Steam Generation units, however, a supplemental firing capability was not considered in the design.

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Final Calculated Modeling Emissions

The short-term and long-term emissions calculated for the power generation turbines to be included in the facility's modeling compliance demonstration are shown in **Table 5-6**.

Table 5-6 Modeling Emissions Summary for Liquefaction Facility Power Generation Turbine

Pollutant		Power Generation Turbine (per turbine)			Reference to Calculation
		Emission (g/s)	Exhaust Temp (°K)	Exhaust Velocity (m/s)	
NO _x	Short-Term	1.84	445	14.6	Sections EC-2 and EC-4
	Long-Term	1.52			
CO	Short-Term	1.00			
PM ₁₀	Short-Term	0.38			
	Long-Term	0.34			
PM _{2.5}	Short-Term	0.38			
	Long-Term	0.34			
SO ₂	Short-Term	0.14			
	Long-Term	0.12			

5.3.3 AQRV Modeling

AQRV modeling is different from criteria pollutant modeling, as it includes additional attention to acid deposition and visibility impacts. Emissions for gaseous pollutants in the AQRV impact assessments were the same as those used in the short-term impact modeling described in **Section 5.3.2**. The short-term particulate matter emissions were speciated for the AQRV analyses as described in the following subsection.

PM Speciation Breakdown

Table 5-7 shows the assumed breakdown and basis for the short-term power generation turbine emissions of the PM₁₀ and PM_{2.5} into filterable and condensable fractions, as required for AQRV modeling.

Table 5-7 AQRV PM Speciation for Liquefaction Facility Power Generation Turbines

Fuel Type	Fine Particulates from Non- Combustion	Elemental Carbon (% Filterable)		Secondary Organic Aerosols (% Condensable)		Reference
		PM _{2.5}	PM ₁₀	PM _{2.5}	PM ₁₀	
Gas	0	29%	29%	71%	71%	AP-42 Table 3.1-2a (USEPA 2009)

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6.0 DEVELOPMENT OF EMISSIONS AND MODELED STACK PARAMETERS : RECIPROCATING INTERNAL COMBUSTION ENGINES (EMERGENCY/NON-EMERGENCY)

6.1 OPERATIONS DESCRIPTION

The reciprocating diesel internal combustion engines listed below are expected to be installed at the Liquefaction Facility.

Auxiliary Air Compressor

The Auxiliary Air Compressor would be provided as a backup air supply to the instrument air system in the event of a power failure or primary instrument air compressor failure. The instrument air system controls all pneumatic instrumentation and valving. In the event of a failure, the facilities valving may require some additional air supply to move into the valve specific fail setting (open or closed).

Diesel Firewater Pump Engine

The Firewater Pump would be diesel-driven and located within the process facilities. There would be one firewater pump designed to distribute 5,000 gallons per minute (gpm) of fire water around the facility in the event of an emergency.

6.2 EMISSIONS DATA SOURCES

Common industry standards for specific equipment types were used to provide emission factors that may be used with engine operating data to estimate the maximum criteria pollutant emission rates allowable under these standards. The tiered engine standards have been provided to vendors as a way to characterize average emissions, rather than “not to exceed” emissions. Because of this, an additional 25% margin was added to the emission factors derived from the standards in order to represent conservative, “not to exceed” emission rates.

Non-Emergency Diesel-Fired Generators

40 CFR Part 60 Subpart IIII (USEPA 2013) was the applicable standard for stationary emergency engines. Per the directions in 40 CFR Part 60 Subpart IIII Section 60.4201 Rule (a) based on the size and build date of the equipment, 40 CFR Part 1039 Subpart B, 1039.102: Control of Emissions from New and In-Use Nonroad Compression-Ignition Engines was the applicable standard for non-emergency engines. The Tier 4 level of emission control was assumed for these units since the equipment would not be installed until 2025. (See **Table 6-1**)

Emergency Diesel-Fired Fire Water Pumps

40 CFR Part 60 Subpart IIII, Appendix Table 4: Emission Standards for Stationary Fire Pump Engines (USEPA 2013) was the applicable standard for fire water pumps. The Tier 2 level of emission control was assumed since the equipment would not be installed until 2025. (See **Table 6-2**)

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Table 6-1 Data Sources for Liquefaction Facility Non-Emergency Diesel Equipment Emissions Estimation

Pollutant	Data Source Description
NO _x	40 CFR Part 1039 Subpart B, 1039.102 (95% of NO _x +NMHC) (USEPA 2010)
CO	40 CFR Part 1039 Subpart B, 1039.102 (USEPA 2010)
VOC	40 CFR Part 1039 Subpart B, 1039.102 (5% of NO _x +NMHC) (USEPA 2010)
PM ₁₀ ¹	40 CFR Part 1039 Subpart B, 1039.102 (USEPA 2010)
PM _{2.5}	Assumed same value as PM ₁₀ for the most conservative estimate
SO ₂	Mass balance assuming all sulfur in the fuel becomes SO ₂ (H ₂ SO ₄ emissions included in SO ₂)
Lead ²	Negligible
Total GHG	40 CFR 98 Subpart C (USEPA 2011)
Total HAPs	AP-42 equipment emission factors, Section 3.3 (USEPA 2009)
NO ₂ /NO _x Ratio	USEPA's default accepted ratio of 0.5 (USEPA 2011)

Note 1: AP-42 emission factor was assumed to be sufficiently conservative for this equipment so that additional particulate matter resulting from the small percentage of sulfur compounds in the fuel were not added.

Note 2: The primary source of lead emissions from combustion sources would be lead additives contained in some fuels that could subsequently be emitted during combustion. Since lead is not an additive to any Liquefaction Facility source fuels, it would only be present at negligible trace levels as a result of engine lubricant constituents or due to engine wear. Therefore, lead emissions are negligible, and the source emissions do not cause or contribute to an exceedance of the lead NAAQS.

Table 6-2 Data Sources for Liquefaction Facility Diesel-Fired Fire Water Pump Emissions Estimation

Pollutant	Data Source Description
NO _x	40 CFR Part 60 Subpart IIII, Appendix Table 4 (95% of NO _x +NMHC) (USEPA 2013)
CO	40 CFR Part 60 Subpart IIII, Appendix Table 4 (USEPA 2013)
VOC	40 CFR Part 60 Subpart IIII, Appendix Table 4 (5% of NO _x +NMHC) (USEPA 2013)
PM ₁₀ ¹	40 CFR Part 60 Subpart IIII, Appendix Table 4 (USEPA 2013)
PM _{2.5}	Assumed same value as PM ₁₀ for the most conservative estimate
SO ₂	Mass balance assuming all sulfur in the fuel becomes SO ₂ (H ₂ SO ₄ emissions included in SO ₂)
Lead ²	Negligible
Total GHG	40 CFR Part 98 Subpart C (USEPA 2011)
Total HAPs	AP-42 equipment emission factors, Section 3.3 (USEPA 2009)
NO ₂ /NO _x Ratio	USEPA's default accepted ratio of 0.5 (USEPA 2011)

Note 1: AP-42 emission factor was assumed to be sufficiently conservative for this equipment so that additional particulate matter resulting from the small percentage of sulfur compounds in the fuel were not added.

Note 2: The primary source of lead emissions from combustion sources would be lead additives contained in some fuels that could subsequently be emitted during combustion. Since lead is not an additive to any Liquefaction Facility source fuels, it would only be present at negligible trace levels as a result of engine lubricant constituents or due to engine wear. Therefore, lead emissions are negligible, and the source emissions do not cause or contribute to an exceedance of the lead NAAQS.

6.3 EMISSION CALCULATION METHODOLOGY FOR DETERMINATION OF POTENTIAL TO EMIT AND MODELING

Information on maximum foreseeable annual emissions was needed to determine the individual equipment and total facility PTE. Calculating the annual tons per year per pollutant was needed for PSD Applicability and for FERC Impact Assessment of facility impacts. Additionally, short-term

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and long-term emissions were calculated for predicting near-field and far-field air quality impacts by means of dispersion modeling. The following sections describe the calculation methods for determining annual tons per year and emissions for other appropriate averaging times as required for modeling.

6.3.1 Potential to Emit for PSD Applicability and FERC Impact Assessment

Annual emission rates to support FERC Impact Assessment were estimated in the same manner used to quantify emissions for comparison to New Source Review PSD Applicability thresholds. Considerations that drove the emission calculations for the diesel-driven engines include annual operating hours and operating load.

Operating Hours and Operating Load

Diesel firewater pump engines and auxiliary emergency equipment typically would operate only during short periodic tests to ensure their operability in an emergency. Recognizing that modeled impacts from such sources would be greatly overestimated if they were assumed to operate continuously at maximum capacity, USEPA has issued guidance (USEPA 2011) that allows a less conservative approach for modeling the impacts from such sources against the short-term ambient standards. Accordingly, the modeling impacts for these sources may use “annualized” emissions, i.e., total annual emissions could be assumed to be spread over all hours of the year to calculate a much lower equivalent hourly rate.

Table 6-3 provides the assumed operational characteristics chosen for the calculation of the intermittent diesel equipment annual emission rates. These assumptions provided a conservative estimate of PTE values for PSD Applicability and FERC Impact Assessment because of the following:

- 500 hours of operation per year was assumed and is much higher than the projected actual operation per year for this equipment (more likely less than 100 hours of operation per year).
- Maximum load for full duration of operation without any variations in load that would typically result in lower emissions.

The emission factor standards used for these diesel-fired equipment are not ambient temperature dependent.

Table 6-3 Assumed Liquefaction Facility Intermittent Diesel Equipment Annual Operations

Pollutant	Annual Operating Hours	Selected Load
NO _x	Maximum Intermittent Operating Hours (500)	Maximum Operating Load (100%)
CO		
VOC		
PM ₁₀		
PM _{2.5}		
SO ₂		
Total GHG		
Total HAPs		

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Final Calculated Annual Emissions

The annual emissions calculated for the intermittent diesel equipment to be included in the facility's PTE summary are shown in **Table 6-4**.

Table 6-4 Liquefaction Facility Intermittent Diesel Equipment PTE Summary

Pollutant		Auxiliary Air Compressor	Diesel Firewater Pump	Reference to Calculation
NO _x	ton/year	0.06	1.13	Sections EC-1 and EC-5
CO	ton/year	0.54	1.03	
VOC	ton/year	0.03	0.06	
PM ₁₀	ton/year	3.08E-03	0.06	
PM _{2.5}	ton/year	3.08E-03	0.06	
SO ₂	ton/year	7.33E-04	1.40E-03	
GHG	tonnes/year	77.9	149	
HAPs	ton/year	2.12E-03	4.07E-03	

6.3.2 Criteria Pollutant Modeling

Conservative estimates of the short-term and long-term emissions from the intermittent diesel equipment were needed to support required dispersion modeling for evaluation of Liquefaction Facility impacts to air quality. Additionally, representative stack parameters (exhaust temperature and velocity) accompanying these emission rates were needed to represent the individual facility sources within the air dispersion model. The long-term annual emissions were calculated with the same methodology used to determine the PTE emissions, as previously described. Also, the short-term emissions for NO_x and SO₂ were annualized in accordance with USEPA modeling guidance (USEPA 2011) for intermittent sources of these pollutants.

Operating Load Selection

Table 6-5 shows the diesel equipment operating load assumptions that were used in determining short-term emission rates for the criteria pollutant dispersion modeling analyses to evaluate NAAQS compliance for all pollutants and averaging times. However, as discussed in **Section 6.3.2**, and allowed by USEPA guidance (USEPA 2011), the "hourly" emission rates used in the modeling for 1-hour NO₂ and 1-hour SO₂ was determined by spreading the annual emissions over the 8,760 hours of the year (annualized). This practice removed the unreasonable conservatism associated with assuming continuous operation for emission units that actually operate only a few hundred hours per year. The annualized emission rates were based on the maximum hourly emission rate derated by a factor of 500 hours/8,760 hours.

The exhaust velocity and exhaust temperature were based on data for a representative combustion engine. Parameters corresponding to the maximum load operation were selected to represent exhaust velocities and temperatures for dispersion modeling, because this is the best understood and most readily available information for diesel engine operation. Although the exclusive use of stack parameters for maximum load operation does not necessarily yield the most conservative possible result for modeling purposes, the exhaust velocity and temperature would not be expected to change appreciably with load during normal equipment testing. Additionally, stack parameters for these engines are almost entirely independent of ambient temperature conditions.

Table 6-6 shows the selection of modeling parameters for evaluating annual average impacts. All annual emission rates were based on the maximum hourly emission rate derated by a factor of 500 hours/8,760 hours.

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Table 6-5 Short-Term Modeling Parameters for Liquefaction Facility Intermittent Diesel Equipment

Pollutant	Emission Type	Emissions	Exhaust Velocity	Exhaust Temperature
		Selected Load	Selected Load	Selected Load
NO _x	1-Hour	100% (Annualized)	Maximum Operating Load (100%)	Maximum Operating Load (100%)
CO	1-Hour	100%		
	8-Hour	100%		
PM ₁₀	24-Hour	100%		
PM _{2.5}	24-Hour	100%		
SO ₂	1-Hour	100% (Annualized)		
	3-Hour	100%		
	24-Hour	100%		

Table 6-6 Long-Term Modeling Parameters for Liquefaction Facility Intermittent Diesel Equipment

Pollutant	Annualized Emissions	Exhaust Velocity	Exhaust Temperature
	Selected Load	Selected Load	Selected Load
NO _x	Maximum Operating Load (100%)	Maximum Operating Load (100%)	Maximum Operating Load (100%)
CO			
PM ₁₀			
PM _{2.5}			
SO ₂			

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Final Calculated Modeling Emissions

The short-term and long-term emissions calculated for the intermittent diesel equipment to be included in the facility's modeling compliance demonstration are shown in **Table 6-7**.

Table 6-7 Modeling Emissions Summary Liquefaction Facility Intermittent Diesel Equipment

Pollutant		Auxiliary Air Compressor			Diesel Fire Water Pump			Reference to Calculation
		Emission (g/s)	Exhaust Temp (°K)	Exhaust Velocity (m/s)	Emission (g/s)	Exhaust Temp (°K)	Exhaust Velocity (m/s)	
NO _x	Short-Term	1.77E-03 (Annualized)	746	35.1	0.03 (Annualized)	760	47.9	Sections EC-2 and EC-5
	Long-Term	1.77E-03			0.03			
CO	Short-Term	0.27			0.52			
PM ₁₀	Short-Term	1.55E-03			0.03			
	Long-Term	8.87E-05			1.71E-03			
PM _{2.5}	Short-Term	1.55E-03			0.03			
	Long-Term	8.87E-05			1.71E-03			
SO ₂	Short-Term (Hourly)	2.11E-05 (Annualized)			4.04E-05 (Annualized)			
	Short-Term (Daily)	3.69E-04			7.08E-04			
	Long-Term	2.11E-05			4.04E-05			

6.3.3 AQRV Modeling

AQRV modeling is different from criteria pollutant modeling as it includes additional attention to acid deposition and visibility impacts. Emissions for gaseous pollutants in the AQRV impact assessments were the same as those used in the other short-term impact modeling described in **Section 6.3.2**. The short-term particulate matter emissions used for the AQRV analysis were speciated as described in the following subsection.

PM Speciation Breakdown

Table 6-8 shows the assumed breakdown and basis for the short-term Liquefaction Facility diesel equipment emissions of the PM₁₀ and PM_{2.5} into filterable and condensable fractions, as required for AQRV modeling.

Table 6-8 AQRV PM Speciation for Liquefaction Facility Intermittent Diesel Engines

Equipment Type	Fuel Type	Fine Particulates from Non-Combustion	Elemental Carbon (% Filterable)		Secondary Organic Aerosols (% Condensable)		Reference
			PM _{2.5}	PM ₁₀	PM _{2.5}	PM ₁₀	
Generator	Diesel	0	86%	87%	14%	13%	AP-42 Table 3.4-2 ¹ (USEPA 2009)
Compressor	Diesel	0	86%	87%	14%	13%	AP-42 Table 3.4-2 ¹ (USEPA 2009)

Note 1: The diesel engines at the Liquefaction Facility would be less than 600 hp. Since no filterable/condensable PM information is provided for engines of this size in AP 42 Section 3.3, the data provided in AP-42 Section 3.4: Large Stationary Diesel Equipment (greater than 600 hp), was used to support the AQRV PM Speciation

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7.0 DEVELOPMENT OF EMISSIONS AND STACK PARAMETERS: FUEL GAS HEATERS

The Liquefaction Facility design does not currently include any gas-fired heaters.

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8.0 DEVELOPMENT OF EMISSIONS AND MODELED STACK PARAMETERS: FLARES

8.1 OPERATIONS DESCRIPTION

Dry and Wet Flare

There would be 2 sets of 3 x 50% Ground Flares, one specifically for dry reliefs and the other for wet reliefs (six total flares), at the Liquefaction Facility. The ground flares would be divided into three different enclosures. The 3 x 50% capacity designation means that during any relief event, two of the three flares would be operating at maximum capacity handling 100% (2 x 50%) of the facility relief stream. The different enclosures would be surrounded by wind and radiation fencing to provide adequate distance from the flare to ensure that the radiation outside of the fence would not exceed 500 BTU/hr/ft² at grade. The flares would be designed for smokeless operation up to 100% of all flow rates.

The Dry Flare would be used for the majority of the relief events from all around the Liquefaction Facility during normal operations. The Wet Flare would receive relief events from the dehydration system regeneration equipment, downstream of the debutanizer system, and from the steam heat medium system. These locations within the facility would potentially be subject to entrainment of water within the gas or liquid which could freeze and form hydrates within the piping.

LP Flare

A Low Pressure Flare would be provided on land to support the arrival of the warm LNG carriers (e.g. full of warm inert gas rather than small amounts of cold LNG), which must be purged of inert gas prior to loading. This elevated sonic LP Flare would not be used for emergency reliefs. It is understood that multiple LNG Carriers a year would call at the marine facility in this warm condition. The warm carriers would have to be purged of gases (potentially remaining hydrocarbon boil-off gas and inert gases), cooled, and pressurized in order to proceed with LNG loading. The LP Flare would receive all gases from warm carriers as well as the Boil-Off Gas Compressor seal gas located in the LNG storage/loading area. Steam would be available as an assist medium for this flare.

Thermal Oxidizer

A Thermal Oxidizer would be located at the Liquefaction Facility as an emissions reduction technique for the hydrocarbon tanks downstream of the fractionation train. The condensate and off-spec condensate storage tanks, as well as the equalization tank that would help to separate oil from the facility's wastewater, would send all vent gas, from working and flash losses, through the Thermal Oxidizer. The Thermal Oxidizer would be sized to provide a required amount of residence time to ensure maximum destruction of VOCs.

8.2 EMISSIONS DATA SOURCE

Common industry references were used to provide emission factors, which were applied with operating data to calculate pollutant emission rates.

Table 8-1 and **Table 8-2** show the references for these emission factors for criteria pollutants, hazardous air pollutants and greenhouse gases.

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Table 8-1 Data Sources for Liquefaction Facility Flare Equipment Emissions Estimation

Pollutant	Data Source Description
NO _x	AP-42 equipment emission factors, Section 13.5 (USEPA 2009)
CO	AP-42 equipment emission factors, Section 13.5 (USEPA 2009)
VOC	AP-42 equipment emission factors, Section 13.5 (USEPA 2009)
PM ₁₀ ¹	AP-42 equipment emission factors, Section 13.5 (USEPA 2009)
PM _{2.5}	Assumed same value as PM ₁₀ for most conservative estimate
SO ₂	Mass balance assuming all sulfur in the fuel becomes SO ₂ (H ₂ SO ₄ emissions included in SO ₂)
Lead ²	Negligible
Total GHG	40 CFR 98 Subpart C (USEPA 2011)
Total HAPs	Ventura County Air Pollution Control District, AB 2588 Combustion Emission Factors (VCAPD 2001)
NO ₂ /NO _x Ratio	USEPA Tier 2 Ambient Ratio Method 2 (ARM2), refer to modeling specific Report for more details

Note 1: PM emissions were included in the analysis for conservatism. It was understood that the smokeless flare design would have low particulate matter emissions. The PM mass emissions were calculated conservatively based on an assumed soot concentration of 40 µg/L for lightly smoking flares as cited in USEPA's AP 42 Compilation of Air Pollutant Emission Factors.

Note 2: The primary source of lead emissions from combustion sources would be lead additives contained in some fuels that could subsequently be emitted during combustion. Since lead is not an additive to any Liquefaction Facility source fuels, it would only be present at negligible trace levels as a result of engine lubricant constituents or due to engine wear. Therefore, lead emissions are negligible, and the source emissions do not cause or contribute to an exceedance of the lead NAAQS.

Table 8-2 Data Sources for Liquefaction Facility Thermal Oxidizer Equipment Emissions Estimation

Pollutant	Data Source Description
NO _x	TCEQ Vapor Oxidizer emission factor (TCEQ 2008)
CO	TCEQ Vapor Oxidizer emission factor (TCEQ 2008)
VOC	TCEQ Vapor Oxidizer emission factor (Same as AP-42 equipment emission factors, Section 1.4) (TCEQ 2008)
PM ₁₀	TCEQ Vapor Oxidizer emission factor (Same as AP-42 equipment emission factors, Section 1.4) (TCEQ 2008)
PM _{2.5}	Assumed same value as PM ₁₀ for most conservative estimate
SO ₂	Mass balance assuming all sulfur in the fuel becomes SO ₂ (H ₂ SO ₄ emissions included in SO ₂)
Lead ¹	Negligible
Total GHG	40 CFR 98 Subpart C (USEPA 2011)
Total HAPs	AP-42 equipment emission factors, Section 1.4 (USEPA 2009)
NO ₂ /NO _x Ratio	USEPA Tier 2 Ambient Ratio Method 2 (ARM2), refer to modeling specific Report for more details

Note 1: The primary source of lead emissions from combustion sources would be lead additives contained in some fuels that could subsequently be emitted during combustion. Since lead is not an additive to any Liquefaction Facility source fuels, it would only be present at negligible trace levels as a result of engine lubricant constituents or due to engine wear. Therefore, lead emissions are negligible, and the source emissions do not cause or contribute to an exceedance of the lead NAAQS.

8.3 EMISSION CALCULATION METHODOLOGY FOR DETERMINATION OF POTENTIAL TO EMIT AND MODELING

Information on maximum foreseeable annual emissions was needed to determine the individual equipment and total facility PTE. Calculating the annual tons per year per pollutant was needed for PSD Applicability determination and for FERC Impact Assessment of facility impacts. Additionally, short-term and long-term emissions were calculated for predicting near-field and

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far-field air quality impacts by means of dispersion modeling. The following sections describe the calculation methods for determining annual tons per year and emissions for other appropriate averaging times as required for modeling.

8.3.1 Potential to Emit for PSD Applicability and FERC Impact Assessment

Annual emission rates to support FERC Impact Assessment were estimated in the same manner used to quantify emissions for comparison with New Source Review PSD Applicability thresholds. Considerations that drove the emission calculations for the flares and the thermal oxidizer include annual operating hours and emergency/normal operating relief rates.

Operating Hours and Operating Load

Emissions from the flare systems were calculated uniquely because they would normally operate continuously at a low throughput, with only a few non-routine events per year during which the flares would operate at a much higher maximum throughput. Purge gas through the headers and pilot gas to keep the flare pilots lit would be combusted by the flares 8,760 hours/year (continuously), while the maximum flaring conditions for the Dry and Wet Flares was conservatively assumed to occur 500 hours/year. The emissions from the 500 hours/year maximum case were annualized over the entire year (500/8,760) and then added to the emissions for the continuous purge/pilot fuel gas feed. The maximum flaring condition for the LP Flare, were based on a specific operating schedule, and were assumed to occur 144 hours/year (6 vessels per year arriving warm, with each requiring 24 hours of flaring). The emissions from the 144 hours/year maximum case were annualized over the entire year (144/8,760) and then were added to the emissions for the continuous purge/pilot fuel gas feed.

The flare PM emission factor in USEPA's *AP-42 Compilation of Air Pollutant Emission Factors* (USEPA 2009) is based on the exhaust flow rate, not the fuel feed rate. An additional calculation was required to determine the full exhaust flow rate from the flare based on the fuel flow mixing with atmospheric air and combusting. The methodology described in 40 CFR 60 Method 19: Determination of Sulfur Dioxide Removal Efficiency and Particulate Matter, Sulfur Dioxide, and Nitrogen Oxide Emission Rates (USEPA 1991) was used to develop the exhaust flow rate based on an assumed dry oxygen concentration in the exhaust. Equation 19-1 of Method 19 was employed to determine the exhaust flow using an Fd factor, fuel flow heat duty, and the O₂ concentration. An Fd factor of 8,710 dscf/MMBtu was used since only gaseous fuel would be combusted in the flares. The Fd factor only accounts for gas with butane (C₄ and lower) as the heaviest component. While other components may be sent to the flares, the majority of hydrocarbon streams at the facility would be natural gas (C₁). The oxygen and water concentrations of the flare exhaust gas were assumed to be similar to standard values used for other external combustion devices (boilers/heaters). Specifically, an oxygen concentration of 3% and a water concentration of 10% were used in the calculation.

The thermal oxidizer would operate continuously with a steady input flow rate of gas sufficient to keep the burner operational and the oxidizer hot, to ensure destruction of VOCs for any variation in gas that may occur.

Table 8-3 and **Table 8-4** provide the assumed operational characteristics selected for the calculation of maximum annual pollutant emissions, based on continuous pilot/purge operation, and intermittent maximum relief operation (flares only).

The flare purge/pilot and thermal oxidizer emissions were conservative because of the following:

- Operation at constant load was assumed for a full year without any variations, which would typically result in lower emissions.

The flare maximum/routine operation emissions were conservative because of the following:

- 500 hours of operation per year was assumed, which is much higher than the projected actual operation (most likely less than 1 hour of operation per year).

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- 144 hours of operation per year was based on the LP Flare handling all warm carrier calls that may occur throughout the year. Six warm calls were assumed with 24 hours of inert gas purging per call.
- Maximum load for full duration of each event, without any variations in load which would typically result in lower emissions.

The emission factors standards that were used for the flares are not ambient temperature dependent.

Table 8-3 Assumed Liquefaction Facility Flare Annual Operations

Pollutant	Annual Operating Hours (Purge/Pilot) All Flares	Annual Operating Hours (Maximum) Dry and Wet Flares	Annual Operating Hours (Routine Operations) LP Flare	Selected Load All Flares
NO _x	Maximum Operating Hours (8,760 hours)	Intermittent Operating Hours (500 hours)	Routine Required Operating Hours (144 hours)	Pilot/Purge: Pilot/Purge Flare Tip Operation Rate (100%) Maximum: Maximum Flare Operation Rate (100%)
CO				
VOC				
PM ₁₀				
PM _{2.5}				
SO ₂				
Total GHG				
Total HAPs				

Table 8-4 Assumed Liquefaction Facility Thermal Oxidizer Annual Operations

Pollutant	Annual Operating Hours	Selected Load All Flares
NO _x	Maximum Operating Hours (8,760 hours)	Maximum Operating Load (100%)
CO		
VOC		
PM ₁₀		
PM _{2.5}		
SO ₂		
Total GHG		
Total HAPs		

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Final Calculated Annual Emissions

The annual emissions calculated for the flares and the thermal oxidizer to be included in the facility's PTE summary are shown in **Table 8-5**.

Table 8-5 Liquefaction Facility Flare and Thermal Oxidizer PTE Summary

Pollutant		Dry Flare (Per Flare)		Wet Flare (Per Flare)		LP Flare (Per Flare)		Thermal Oxidizer	Reference to Calculation
		Purge/ Pilot	Max	Purge/ Pilot	Max	Purge/ Pilot	Max		
NO _x	ton/year	2.13	1,020	0.67	238	3.13	5.14	2.63	Section EC-1 and EC-6/EC-7
CO	ton/year	9.71	4,650	3.06	1,090	14.3	22.4	2.17	
VOC	ton/year	17.9	8,550	5.62	2,000	26.2	40.9	0.14	
PM ₁₀	ton/year	0.88	423	0.28	98.9	1.3	2.03	0.20	
PM _{2.5}	ton/year	0.88	423	0.28	98.9	1.3	2.03	0.20	
SO ₂	ton/year	0.08	37.4	0.02	8.74	0.22	0.20	0.07	
GHG	tonnes/year	3,330	1,593,200	1,050	372,300	4,890	7,630	2,800	
HAPs	ton/year	0.09	43.5	0.03	10.2	0.13	0.21	0.05	

8.3.2 Criteria Pollutant Modeling

Conservative estimates of the short-term and long-term emissions from the flares and thermal oxidizer were needed to support required dispersion modeling for evaluation of Liquefaction Facility impacts to air quality. Additionally, representative stack parameters (exhaust temperature and velocity) accompanying these emission rates were needed to represent the individual facility sources within the air dispersion model. The long-term (annual) emissions were calculated with the same methodology used to determine the PTE emissions, as previously described. Also, the short term emissions for NO_x and SO₂ were annualized in accordance with USEPA guidance (USEPA 2011) on calculating emissions for modeling of intermittent sources.

Operating Load Selection

The flares required two separate emissions calculations: one for the purge/pilot emissions that would occur continuously for 8,760 hours/year, and another for the emergency and routine maximum flaring cases that were assumed to occur 500 hours per year for the Dry and Wet flares and 144 hours per year for the LP Flare. Emissions for the maximum flaring cases were annualized over the entire year (derated by a factor of either 500 hours/8,760 hours or 144 hours/8,760 hours). All emissions were modeled at the same location.

Table 8-6 lists the flare operational characteristics assumed for the calculation of short-term modeled emission rates.

The exhaust velocity was 20 m/s, a recommended modeling value described in the Project Modeling Reports.

The exhaust temperature was 1,273°K, a recommended modeling value described in the Project Modeling Reports.

In accordance with USEPA Guidance (USEPA 1995), flares also required an additional consideration for the calculation of their modeled heights and diameters. It is understood that flares are different from most other emissions sources in that the gas combustion occurs at the exit point into the atmosphere, rather than upstream of the stack inlet. Because of the location of the emissions release above the flame, the height of plume release will actually be much higher than the physical stack height. For this reason, an effective height was calculated to simulate a taller stack to better represent the true plume elevation. An effective diameter was also calculated

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for the flares to account for the correct initial size of the plume after the combustion has occurred beyond the flare exit. Both the effective height and effective diameter were estimated based on the heat release rate of the gas flow to the flare prior to combustion. Detailed development of the effective stack heights and diameters are shown in **Section EC-6**.

Table 8-7 summarizes the operational loads that were assumed to develop the thermal oxidizer emission rates and stack parameters for the short-term dispersion modeling (averaging times of 1 to 24 hours).

The exhaust velocity was based on the maximum load operation of the thermal oxidizer. This value is not dependent on ambient temperature.

The exhaust temperature was based on the maximum load operation of the thermal oxidizer. This value is not dependent on ambient temperatures.

Table 8-8 and **Table 8-9** summarize the information for development of annual flaring and thermal oxidizer emission estimates. All annual emission rates for the maximum/emergency operating scenarios were based on the maximum hourly emission rate derated by a factor of 500 hours/8,760 hours. The routine flaring operation emission rates for the LP Flare were derated using a factor of 144 hours/8,760 hours.

Table 8-6 Short-Term Modeling Parameters for the Liquefaction Facility Flares

Pollutant	Emission Type	Purge/Pilot Emissions	Maximum/Routine Operation Emissions	Exhaust Velocity	Exhaust Temperature
		Selected Load	Selected Load		
NO _x	1-Hour	Purge/Pilot Operating Load (100%)	Maximum Operating Load (100%)	USEPA and ADEC Standard (20 m/s)	USEPA and ADEC Standard (1,273°K)
CO	1-Hour				
	8-Hour				
PM ₁₀	24-Hour				
PM _{2.5}	24-Hour				
SO ₂	1-Hour				
	3-Hour				
	24-Hour				

Table 8-7 Short-Term Modeling Parameters for the Liquefaction Facility Thermal Oxidizer

Pollutant	Emission Type	Emissions	Exhaust Velocity	Exhaust Temperature
		Selected Load	Selected Load	Selected Load
NO _x	1-Hour	Maximum Operating Load (100%)	Maximum Operating Load (100%)	Maximum Operating Load (100%)
CO	1-Hour			
	8-Hour			
PM ₁₀	24-Hour			
PM _{2.5}	24-Hour			
SO ₂	1-Hour			
	3-Hour			
	24-Hour			

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Table 8-8 Long-Term Modeling Parameters for the Liquefaction Facility Flares

Pollutant	Purge/Pilot Emissions	Maximum/ Routine Operation Emissions	Exhaust Velocity	Exhaust Temperature
	Selected Load	Selected Load		
NO _x	Purge/Pilot Operating Load (100%)	Maximum Operating Load (100%)	USEPA and ADEC Standard (20 m/s)	USEPA and ADEC Standard (1,273°K)
CO				
PM ₁₀				
PM _{2.5}				
SO ₂				

Table 8-9 Long-Term Modeling Parameters for the Liquefaction Facility Thermal Oxidizer

Pollutant	Emissions	Exhaust Velocity	Exhaust Temperature
	Selected Load	Selected Load	Selected Load
NO _x	Maximum Operating Load (100%)	Maximum Operating Load (100%)	Maximum Operating Load (100%)
CO			
PM ₁₀			
PM _{2.5}			
SO ₂			

Final Calculated Modeling Emissions

The short-term and long-term emissions calculated for the flares to be included in the facility's modeling compliance demonstration are shown in **Table 8-10**, **Table 8-11**, and **Table 8-12**.

Table 8-10 Modeling Emissions Summary for Liquefaction Facility Flares

Pollutant		Dry Flare Flare (Per Flare)				Reference to Calculation
		Purge/Pilot Emission (g/s)	Maximum Emissions (g/s)	Exhaust Temp (°K)	Exhaust Velocity (m/s)	
NO _x	Short-Term	0.06	29.3 (Annualized)	1,273	20	Sections EC-2 and EC- 6
	Long-Term	0.06	29.3			
CO	1-hour	0.28	1,170			
	8-hour	0.28	146			
PM ₁₀	Short-Term	0.03	4.44			
	Long-Term	0.03	12.2			
PM _{2.5}	Short-Term	0.03	4.44			
	Long-Term	0.03	12.2			
SO ₂	Short-Term (Hourly)	2.17E-03	1.08 (Annualized)			
	Short-Term (Daily)	2.17E-03	3.14			
	Long-Term	2.17E-03	1.08			

Table 8-11 Modeling Emissions Summary for Liquefaction Facility Flares

Pollutant		Wet Flare (Per Flare)				LP Flare (Per Flare)				Reference to Calculation
		Purge/Pilot Emission (g/s)	Maximum Emissions (g/s)	Exhaust Temp (°K)	Exhaust Velocity (m/s)	Purge/Pilot Emission (g/s)	Maximum Emissions (g/s)	Exhaust Temp (°K)	Exhaust Velocity (m/s)	
NO _x	Short-Term	0.02	6.86 (Annualized)	1,273	20	0.09	0.15 (Annualized)	1,273	20	Sections EC-2 and EC-6
	Long-Term	0.02	6.86			0.09	0.15			
CO	1-hour	0.09	274			0.41	39.2			
	8-hour	0.09	34.2			0.41	39.2			
PM ₁₀	Short-Term	8.00E-03	1.04			0.04	3.55			
	Long-Term	8.00E-03	2.85			0.04	0.06			
PM _{2.5}	Short-Term	8.00E-03	1.04			0.04	3.55			
	Long-Term	8.00E-03	2.85			0.04	0.06			
SO ₂	Short-Term (Hourly)	7.09E-04	0.25 (Annualized)			6.36E-03	5.67E-03 (Annualized)			
	Short-Term (Daily)	7.09E-04	0.73			6.36E-03	0.35			
	Long-Term	7.09E-04	0.25			6.36E-03	5.67E-03			

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Table 8-12 Modeling Emissions Summary for Liquefaction Facility Thermal Oxidizer

Pollutant		Thermal Oxidizer			Reference to Calculation
		Emission (g/s)	Exhaust Temp (°K)	Exhaust Velocity (m/s)	
NO _x	Short-Term	0.08	1,255	8.90	Sections EC-2 and EC-7
	Long-Term	0.08			
CO	Short-Term	0.06			
PM ₁₀	Short-Term	5.64E-03			
	Long-Term	5.64E-03			
PM _{2.5}	Short-Term	5.64E-03			
	Long-Term	5.64E-03			
SO ₂	Short-Term (Hourly)	2.07E-03			
	Short-Term (Daily)	2.07E-03			
	Long-Term	2.07E-03			

8.3.3 AQRV Modeling

AQRV modeling is different from criteria pollutant modeling in that it includes additional attention to acid deposition and visibility impacts. Emissions for gaseous pollutants in the AQRV impact assessments were the same as those used in the other short-term impact modeling described in **Section 8.3.2**. The short-term particulate matter emissions were speciated in the AQRV analysis as described in the following subsection.

PM Speciation Breakdown

Table 8-13 and **Table 8-14** show the assumed breakdown and basis for the short-term Liquefaction Facility flare and thermal oxidizer emissions of the PM₁₀ and PM_{2.5} into filterable and condensable fractions, as required for AQRV modeling.

Table 8-13 AQRV PM Speciation for Liquefaction Facility Flares

Fuel Type	Fine Particulates from Non-Combustion	Elemental Carbon (% Filterable)		Secondary Organic Aerosols (% Condensable)		Reference
		PM _{2.5}	PM ₁₀	PM _{2.5}	PM ₁₀	
Gas	0	25%	25%	75%	75%	AP-42 Table 1.4-2 (pilot/purge fuel gas, assumed as external combustion source) (USEPA 2009)

Table 8-14 AQRV PM Speciation for Liquefaction Facility Thermal Oxidizer

Fuel Type	Fine Particulates from Non-Combustion	Elemental Carbon (% Filterable)		Secondary Organic Aerosols (% Condensable)		Reference
		PM _{2.5}	PM ₁₀	PM _{2.5}	PM ₁₀	
Gas	0	25%	25%	75%	75%	AP-42 Table 1.4-2 (USEPA 2009)

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9.0 LIQUEFACTION FACILITY MOBILE SOURCES

Mobile sources typically are not included in a PSD Applicability assessment or in PSD modeling. However, mobile source emissions associated with the operational Liquefaction Facility were provided for full assessment of potential Project impacts to air quality in FERC Resource Report 9 submittal. The following sections describe the intended methodology for developing this information.

9.1.1 On Land

There is currently no inventory proposed for the Liquefaction Facility that addresses the required mobile and/or non-road equipment associated with its operation. The current GTP inventory of mobile sources was assumed to be conservatively representative for the Liquefaction Facility, which would be a fairly comparably sized facility. The mobile source emissions were conservative due to the harsher climate and more remote location of the GTP facility. These factors required additional snow removal equipment and man camp/personnel vehicles.

Emissions of NO_x, CO, VOC, SO₂, PM₁₀, PM_{2.5}, CO₂, CH₄, N₂O, and HAPs from on-road equipment associated with routine operations were estimated based on USEPA's MOVES2014 motor vehicle emissions estimation program. The latest county-specific MOVES2014 input data available from ADEC was used and adjusted to approximate on-road emission factors for 2027. The assumed first full year of normal operation that does not include additional overlapping construction activities. As previously stated, construction-related emissions are not included in this Report.

The MOVES-generated emission factors (g/mi) for individual vehicle categories were multiplied by the average speeds of the equipment and the corresponding yearly operating hours to estimate annual emissions. The annual operating hours per unit for the vehicles were estimated based on assumed operations of 5 hours per day for garbage and food delivery trucks, 10 hours per month for various delivery and hazardous waste trucks, 20 hours per month for maintenance personnel and vacuum trucks, and 120 hours per month for the intercity bus operation. It was assumed that idling time has been included in the operating hours provided by the facility design team. All emissions were calculated in lb/hr and tons per year. All on-road vehicle types considered for mobile emissions are shown in **Table 9-1**.

The non-road emissions include mobile vehicles that would only be operated on-site, such as cranes and backhoes. Additionally, portable emissions sources were included in this category such as mobile generator sets or air compressors. These portable emission sources would not produce emissions while moving, but would not be bound to one location. The non-road emissions were calculated using Tier 4 standards from the NON-ROAD program for NO_x, CO, PM, and Total Hydrocarbon (THC). The equipment type was assigned a Standard Classification Code (SCC) which connects the equipment type to the emissions. In addition to the emission factors for each pollutant, a load factor from the NMIM/NONROAD08 model factors (USEPA 2010) was applied to the diesel engine capacity to account for efficiency of the engine and to more accurately calculate emissions per normal operating horsepower output. All non-road vehicle types considered for mobile emissions are shown in **Table 9-1**.

Table 9-1 Liquefaction Facility Emitting Mobile and Non-Road Equipment Types

Source Type	Source Description
Mobile	Single Unit Short-Haul Truck
	Light Commercial Truck
	Intercity Bus
	Passenger Truck
Non-Road	Light Commercial Air Compressor
	Graders
	Tractors/Loaders/Backhoes
	Crane
	Rubber Tire Dozer
	Rubber Tire Loader
	Light Commercial Generator Set
	Forklifts
	Aerial Lift
	Skid Steer Loader
	Light Commercial Welders

9.1.2 Marine

9.1.2.1 Facility Supply Vessels

Cargo shipments to the Liquefaction Facility would be coming from surrounding Alaskan cities (mainly Anchorage) via barge and assisting tow tug. The emissions from the trips to the Liquefaction Facility were based on the assumed size of the tow tug and emissions factors from the USEPA's *Current Methodologies in Preparing Mobile Source Port-Related Emissions Inventories* (USEPA 2009), Harbor Craft Emissions Table 3-8. A fleet mixture of Tier 1 and Tier 2 harbor craft emissions, which are applicable to older vessels, were assumed, since these vessels would be operated by a third party and are likely to represent a range of ages. No emissions were assumed for the barges. A barge with propulsion capabilities was assumed to have the same engine size as an appropriate tow tug. Therefore, only one common emissions rate per distance was assumed for all barge/tow activity. All emissions were calculated in units of lb/hr and tons per year.

9.1.2.2 LNG Marine Equipment

Two different sets of emissions were used to represent the Liquefaction Facility marine terminal operations and emissions. For FERC Impact Assessment, all emissions within state waters were calculated for both the LNG carriers and support tugs. For modeling, only emissions produced by the LNG carriers and support tugs within 500 meters of the terminal were considered to be associated with the facility.

The sources of the emission factors that were used to quantify emissions for each marine vessel type associated with the Liquefaction Facility marine are described in **Table 9-2**.

Table 9-2 Data Sources for Marine Equipment Emissions Estimation

Table 3-2 Data Sources for Marine Equipment Emissions Estimation						
Pollutant	Engine Tier Assumption	Category 1 Auxiliary Engine	Category 2 Auxiliary Engine	Category 3 Auxiliary Engine	Internal Combustion Main Propulsion	Steam Main Propulsion
NO _x	Tier 1 & 2	40 CFR 1042 Subpart J		40 CFR 1042 Subpart B		Port-Related Emissions Inventories
	Tier 3 & 4	40 CFR 1042 Subpart B				
CO	Tier 1 & 2	40 CFR 1042 Subpart J				
	Tier 3 & 4	40 CFR 1042 Subpart B				
VOC	Tier 1 & 2	40 CFR 1042 Subpart J				
	Tier 3 & 4	40 CFR 1042 Subpart B				
PM ₁₀	Tier 1 & 2	40 CFR 1042 Subpart J		Port-Related Emissions Inventories		
	Tier 3 & 4	40 CFR 1042 Subpart B				
PM _{2.5}	Tier 1 & 2	40 CFR 1042 Subpart J				
	Tier 3 & 4	40 CFR 1042 Subpart B				
SO ₂	Tier 1 & 2	Mass Balance assuming ULSD with 15 ppm sulfur				
	Tier 3 & 4					
Lead ¹	Tier 1 & 2	Negligible				
	Tier 3 & 4					
Total GHG	Tier 1 & 2	Port-Related Emissions Inventories				
	Tier 3 & 4					
Total HAPs	Tier 1 & 2	AP-42 equipment emission factors, Section 3.3				
	Tier 3 & 4					
Note 1: The primary source of lead emissions from combustion sources would be lead additives contained in some fuels that could subsequently be emitted during combustion. Since lead is not an additive to any Liquefaction Facility source fuels, it would only be present at negligible trace levels as a result of engine lubricant constituents or due to engine wear. Therefore, lead emissions are negligible, and the source emissions do not cause or contribute to an exceedance of the lead NAAQS.						

It is currently estimated that 204 LNG carrier vessels per year would call at the Nikiski facility to receive LNG loads for shipment. While it would be possible for two LNG carriers to be docked at the terminal at the same time, it would not be possible for both to be loading LNG simultaneously. Each LNG carrier call is anticipated to last roughly 34.5 hours, with the majority of time, 18 hours, spent hoteling/loading. Additional LNG Carrier operation modes considered within each call are:

- Cruising – vessel at full speed near state-water boundary
- Approach – vessel has slowed to near-terminal speeds, but still outside of terminal boundaries
- Maneuvering – vessel moving into or out of port
- Cool down – stationary phase subsequent to docking
- Hoteling – vessel is stationary at dock but not loading
- Loading – loading LNG
- Purge lines – stationary phase after loading finishes, just prior to undocking

LNG Carriers emissions come from both the main propulsion systems (steam boiler, steam turbine powered or diesel-electric) and the auxiliary diesel engines that would be used to provide power for onboard electrical needs. **Table 9-3** shows the assumptions for each operational mode per marine terminal call, assuming the normal cold arrival of a LNG Carrier. **Table 9-4** describes the assumptions for each operation mode per call for a warm LNG Carrier arrival, which would entail additional time to purge the vessel of inert gas and cool it prior to LNG loading.

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Table 9-3 LNG Carrier Operational Modes Per Call – Normal Cold Arrival

Operation Mode	Main Propulsion Engine		Auxiliary Diesel Enigne	
	Time in Mode (hr)	Selected Load	Time in Mode (hr)	Selected Load
Cruising IN	0.8	80%	0.8	80%
Approach IN	2.0	25%	2.0	80%
Far-Terminal Operation Maneuvering IN ¹	1.0	15%	1.0	80%
Near-Terminal Operation Maneuvering IN ¹	1.0	15%	1.0	80%
Cool Down/Vessel Purge	3.5	0% (Shut Down)	3.5	80%
LNG Loading/Hoteling	18	0% (Shut Down)	18	53% (If Loading) 20% (If Hoteling)
Line Purge/Prep	3.5	0% (Shut Down)	3.5	80%
Near-Terminal Operation Maneuvering OUT ¹	1.0	15%	1.0	80%
Far-Terminal Operation Maneuvering OUT ¹	1.0	15%	1.0	80%
Approach OUT	2.0	25%	2.0	80%
Cruising OUT	0.8	80%	0.8	80%

Note 1: Far-Terminal and Near-Terminal operations were differentiated by the distance from the terminal where they occur. Far-Terminal applied to anything outside of a 500 meter radius from the terminal, while Near-Terminal was all activity occurring within 500 meters.

Table 9-4 LNG Carrier Operational Modes Per Call – Warm Arrival

Operation Mode	Main Propulsion Engine		Auxiliary Diesel Enigne	
	Time in Mode (hr)	Selected Load	Time in Mode (hr)	Selected Load
Cruising IN	0.8	80%	0.8	80%
Approach IN	2.0	25%	2.0	80%
Far-Terminal Operation Maneuvering IN ¹	1.0	15%	1.0	80%
Near-Terminal Operation Maneuvering IN ¹	1.0	15%	1.0	80%
Cool Down/Vessel Purge	48	0% (Shut Down)	48	80%
LNG Loading/Hoteling	18	0% (Shut Down)	18	53% (If Loading) 20% (If Hoteling)
Line Purge/Prep	3.5	0% (Shut Down)	3.5	80%
Near-Terminal Operation Maneuvering OUT ¹	1.0	15%	1.0	80%
Far-Terminal Operation Maneuvering OUT ¹	1.0	15%	1.0	80%
Approach OUT	2.0	25%	2.0	80%
Cruising OUT	0.8	80%	0.8	80%

Note 1: Far-Terminal and Near-Terminal operations were differentiated by the distance from the terminal where they occur. Far-Terminal applied to anything outside of a 500 meter radius from the terminal, while Near-Terminal was all activity occurring within 500 meters.

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Since most of the fleet would be purpose built, it is expected that the propulsion systems for the LNG carriers loading at the terminal would be dominated by internal combustion (IC) engines, rather than steam turbine engines. Therefore, when calculating emissions, 98% of the carriers loading at the facility were assumed to be powered by IC engines with the remaining 2% powered by steam driven units. Additionally, it was assumed that the vessels powered by IC engines would comprise a fleet of roughly 80% purpose-built vessels and 20% vessels of opportunity. The latter vessels could only arrive at the terminal during the summer periods. The fleet mix that was used for emissions estimation purposes assumed compliance with the International Maritime Organization (IMO) vessel emissions requirements for year 2025 for all purpose-built ships. The IMO standards require Tier 3 from the Port Related Emissions Inventory document and from 40 CFR 1042: Control of Emissions from New and In-Use Marine Compression-Ignition Engines (USEPA 2013) and Vessels and higher emission controls for all engine categories by 2025.

A fleet-weighted average emission factor was used to account for the vessels of opportunity, which could potentially have engines rated at the lower IMO tiers since they could have been built during a previous year. The same type of fleet mix evaluation and weighted emission factors was used for the LNG carrier auxiliary engines.

There would be five facility-dedicated tugs located at the berth at all times, however only four would ever be operating concurrently. The four tugs would be used to assist the LNG Carriers embarking and disembarking within 500 meters of the facility. There would be one additional tug available as a redundant (spare) tug, in the event any other tug requires maintenance such as propeller replacement or cooling system maintenance.

The tug operations were determined based on how they would assist during the LNG Carrier call operational modes. There is a total of 39 hours of tug operation associated with each normal/cool LNG Carrier call, and it is assumed that no additional ice clearing was required in the summer months. The warm LNG Carrier Calls include 69 hours of associated tug operation to account for additional tug needs during the purging and cooling of the LNG Carrier at the berth, again, the tug operation assumes no additional ice clearing during the summer months. Tug operations would only consist of maneuvering and idling. **Table 9-5** describes engine assumptions for each operational mode of the tugs per normal/cool LNG Carrier vessel call without additional ice management requirements (summer). **Table 9-6** describes engine assumptions for each operational mode of the tugs per warm LNG Carrier vessel call without additional ice management requirements (summer). **Table 9-7** describes engine assumptions for each operational mode of the tugs per normal/cool LNG Carrier vessel call with additional ice management requirements (winter). **Table 9-8** describes engine assumptions for each operational mode of the tugs per warm LNG Carrier vessel call with additional ice management requirements (winter).

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Table 9-5 Tug Operational Modes Per LNG Carrier Call – Normal No Ice

Operation Mode	Tug Maneuvering			Tug Idling		
	# of Tugs	Time in Mode (hr)	Selected Load	# of Tugs	Time in Mode (hr)	Selected Load
Carrier Arrival	--	--	--	1	4.0	10%
Approach Cruising IN	1	1.0	75%	3	1.0	10%
Far-Terminal Operation Maneuvering IN	4	1.0	75%	--	--	--
Near-Terminal Operation Maneuvering IN	4	1.0	75%	--	--	--
Carrier Guarding	1	25.0	75%	3	25.0	10%
Near-Terminal Operation Maneuvering OUT	4	1.0	75%	--	--	--
Far-Terminal Operation Maneuvering OUT	4	1.0	75%	--	--	--
Cruising OUT	1	1.0	75%	3	1.0	10%
Carrier Dispatch	--	--	--	1	4.0	10%
Total Tug Operation per LNG Carrier Call					39	hours

Table 9-6 Tug Operational Modes Per LNG Carrier Call – Warm No Ice

Operation Mode	Tug Maneuvering			Tug Idling		
	# of Tugs	Time in Mode (hr)	Selected Load	# of Tugs	Time in Mode (hr)	Selected Load
Carrier Arrival	--	--	--	1	4.0	10%
Approach Cruising IN	1	1.0	75%	3	1.0	10%
Far-Terminal Operation Maneuvering IN	4	1.0	75%	--	--	--
Near-Terminal Operation Maneuvering IN	4	1.0	75%	--	--	--
Carrier Guarding	1	55.0	75%	3	55.0	10%
Near-Terminal Operation Maneuvering OUT	4	1.0	75%	--	--	--
Far-Terminal Operation Maneuvering OUT	4	1.0	75%	--	--	--
Cruising OUT	1	1.0	75%	3	1.0	10%
Carrier Dispatch	--	--	--	1	4.0	10%
Total Tug Operation per LNG Carrier Call					69	hours

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Table 9-7 Tug Operational Modes Per LNG Carrier Call – Normal with Ice Management

Operation Mode	Tug Maneuvering			Tug Idling		
	# of Tugs	Time in Mode (hr)	Selected Load	# of Tugs	Time in Mode (hr)	Selected Load
Carrier Arrival	1	4.0	75%	1	4.0	10%
Approach Cruising IN	2	1.0	75%	2	1.0	10%
Far-Terminal Operation Maneuvering IN	4	1.0	75%	--	--	--
Near-Terminal Operation Maneuvering IN	4	1.0	75%	--	--	--
Carrier Guarding	2	25.0	75%	2	25.0	10%
Near-Terminal Operation Maneuvering OUT	4	1.0	75%	--	--	--
Far-Terminal Operation Maneuvering OUT	4	1.0	75%	--	--	--
Cruising OUT	1	1.0	75%	3	1.0	10%
Carrier Dispatch	--	--	--	1	4.0	10%
Total Tug Operation per LNG Carrier Call					39	hours

Table 9-8 Tug Operational Modes Per LNG Carrier Call – Warm with Ice Management

Operation Mode	Tug Maneuvering			Tug Idling		
	# of Tugs	Time in Mode (hr)	Selected Load	# of Tugs	Time in Mode (hr)	Selected Load
Carrier Arrival	1	4.0	75%	1	4.0	10%
Approach Cruising IN	2	1.0	75%	2	1.0	10%
Far-Terminal Operation Maneuvering IN	4	1.0	75%	--	--	--
Near-Terminal Operation Maneuvering IN	4	1.0	75%	--	--	--
Carrier Guarding	2	55.0	75%	2	55.0	10%
Near-Terminal Operation Maneuvering OUT	4	1.0	75%	--	--	--
Far-Terminal Operation Maneuvering OUT	4	1.0	75%	--	--	--
Cruising OUT	1	1.0	75%	3	1.0	10%
Carrier Dispatch	--	--	--	1	4.0	10%
Total Tug Operation per LNG Carrier Call					69	hours

The annual PTE emissions for marine sources associated with the Liquefaction Facility were calculated based on a total of 204 calls per year for all types of Carrier arrivals (normal/cool and warm) and also additional ice management requirements during the months of December through May. The total emissions for each call were calculated based on the load and time assumptions given in **Tables 9-3** through **Table 9-8**.

Maximum modeled 1-hour emissions for the marine terminal were based on a conservative assumption of two LNG Carriers calling at nearly the same time. The scenario entailed the first LNG carrier purging its lines in preparation for departing the southern berth after completing LNG

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loading, while the second carrier begins loading at the northern berth. While both carriers are docked, two tugs are present at all times around the terminal. Both tugs are operating at a high engine load, as one guards the carriers within 800 feet and the other assists with ice maintenance, ensuring that the ice in the area does not prevent carrier arrivals and departures.

Maximum modeled 24-hour marine vessel emissions were also based on a conservative assumption involving two LNG Carriers calling at nearly the same time. This scenario entailed one carrier beginning to load LNG at the southern berth, while a second incoming carrier begins maneuvering within 500 meters of the northern berth with the assistance of all four tugs at a high engine load. Once the second carrier has been docked, it would begin cooling down and purging the vessel cargo compartments in preparation for LNG loading, while two of the tugs return to a standby mode outside of the 500 meter zone. The other two tugs would remain near the carriers at a high engine load to guard the carriers within 800 feet and to assist with ice maintenance operations. After the first carrier has completed the 18 hours of LNG loading, it would begin to purge its lines and prepare for departure from the terminal, while the second carrier commences LNG loading. When the first carrier is ready to depart, all four tugs would be used to maneuver it out of the 500 meter near-terminal operation area, after which two tugs would return to the berth to resume carrier guarding and ice clearing.

The engine load percentages shown in **Tables 9-3** through **Table 9-8** were used to calculate an engine output for each vessel operational mode described in the worst-case short-term scenarios described above. The fleet-weighted emission factors for the LNG Carriers and the tug emission factors were then applied to the operating loads to produce emission rates for each mode that would occur within the specified averaging period.

The LNG Carrier and tug exhaust velocities were calculated because of the current lack of available engine-specific information. Stack diameters for the vessels were assumed based on permitted vessel stack parameters from the Corpus Christi Liquefaction LLC project (Chenier 2013). 40 CFR 60 Method 19: Determination of Sulfur Dioxide Removal Efficiency and Particulate Matter, Sulfur Dioxide, and Nitrogen Oxide Emission Rates (USEPA 1991) was used to estimate the exhaust flow rates based on an assumed dry oxygen concentration in the exhaust. Equation 19-1 of Method 19 was employed to determine the exhaust flow using an Fd factor, engine output power, and the O₂ concentration. An Fd factor of 9,190 dscf/MMBtu was used since only diesel oil would be used as the fuel for the vessels. The oxygen and water concentrations were assumed to be 8% and a 6.5%, respectively, based on available data for other internal combustion devices (generators/turbines).

9.1.3 Final Mobile and Marine Emissions

The emissions from the mobile and non-road/portable sources used for calculating the potential emissions from mobile equipment are shown in **Sections EC-12** and **EC-13**.

The emissions from the offsite sources used for the near field and far-field modeling are shown in **Sections MEC-1** through **MEC-19**.

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10.0 OFF-SITE EMISSIONS SOURCES

The previous sections of this Report have described the development of air pollutant emissions information for the specific sources within the Project facility. This section provides comparable information on the methods that were used to characterize the emissions of off-site facilities that were included explicitly in predicting near-field and far-field cumulative impacts. For purposes of this discussion, “near-field” impacts were those predicted to occur at receptors within a 50-kilometer radius from the Liquefaction Facility, whereas “far-field” impacts were those at distances greater than 50 kilometers. The PSD modeling that was conducted to evaluate near-field cumulative impacts of the Liquefaction Facility for comparison with ambient air quality standards and increment limits explicitly included emissions from existing facilities at Nikiski. Data for the existing facilities were determined from facility permit documents and model input and output files from previous modeling analyses. Assessment of far-field impacts to air quality and AQRVs in Class I and sensitive Class II areas in Alaska required development of much larger modeling emissions inventories of existing sources that were compiled using national and state electronic databases. These emissions data on existing facilities were augmented with estimates for reasonably foreseeable future sources in the project areas that are currently undergoing permitting or construction. The following sections describe the methods and resources that were used to construct the emissions data needed to support both types of modeling analyses.

10.1 EMISSIONS DATA FOR NEAR-FIELD IMPACT ANALYSES

10.1.1 Cumulative Liquefaction Facility Modeling

Existing emissions sources in the vicinity of the proposed Project’s Liquefaction Facility site include:

- Tesoro Refinery
- Existing ConocoPhillips Company (COP) Kenai LNG Facility (including ships)
- Agrium Kenai Nitrogen Plant and Loading Terminal (including ships)
- Homer Electric Association (HEA) Bernice Lake Power Plant
- Tesoro Kenai Pipe Line (KPL) Marine Loading Terminal (including ships)
- HEA Nikiski Generation Plant

These facilities and associated marine vessels were included explicitly in the NAAQS and PSD increment compliance modeling for the Liquefaction Facility. Other relatively nearby sources were either considered incapable of producing a significant concentration gradient at the Liquefaction Facility site or had impacts that were captured as part of monitored background concentrations included as part of the cumulative impact analysis. As many of the individual emission units at these facilities operate intermittently, it was considered overly conservative to model them at their full PTE levels simultaneously. Furthermore, USEPA has recently proposed modifications to the Guideline on Air Quality Models (USEPA 2011) that explicitly allows for representing nearby sources in cumulative impact analyses at their actual operating conditions. Accordingly, modeling to evaluate cumulative impacts of the Liquefaction Facility used actual operating emissions for the off-site sources listed above in both the NAAQS and PSD increment compliance assessments.

The marine emissions for both the short-term and long-term modeling impacts were calculated based on a known 2010 inventory within the Cook Inlet, then scaled by an annual growth rate for increased activity to account for development of the Liquefaction Facility not occurring until much later. There is only one berth present, therefore only one vessel can call at a time. The maximum

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emissions from all vessel types was assumed for the short-term emissions and the increased total calls per year was assumed at the maximum emissions rate for the total annual.

Modeling representations of the listed off-site sources were determined from a cumulative analysis conducted for a recent construction permitting project at Nikiski (Agrium), and actual emissions for these facilities were taken from the ADEC point source emissions inventory for 2011 to match the NEI Database (NEI 2011) that was used to support the far-field air quality and AQRV modeling analyses. No stack parameter information was available for modeling the vessels, the offsite source vessels were assumed to have the same stack parameters as the Liquefaction Facility marine terminal.

The ARM2 NO and NO₂ chemical transformation algorithm was used for predicting cumulative NO₂ impacts. This method does not rely on source-specific in-stack ratios, but rather applies an ambient ratio to the 1-hour modeled NO_x concentrations based on a formula derived empirically from ambient monitored ratios of NO₂/NO_x. It includes default upper and lower limits on the ambient ratio applied to the modeled concentration of 0.9 and 0.2, respectively.

Speciation of particulate matter emissions from the off-site emission units was estimated using PM₁₀/PM_{2.5} splits for the appropriate facility equipment categories, as provided in the USEPA AP-42 compilation (USEPA 2009). The relevant splits and corresponding AP-42 citations are presented in **Table 10-1**.

Table 10-1 PM Speciation Assumed for Equipment at Nikiski Off-Site Sources

Equipment	Fuel Type	Fine Particulates from Non-Combustion	Elemental Carbon (% Filterable)		Secondary Organic Aerosols (% Condensable)		Reference
			PM _{2.5}	PM ₁₀	PM _{2.5}	PM ₁₀	
Turbines	Gas	0	29%	29%	71%	71%	AP-42 Table 3.1-2a (USEPA 2009)
Heaters/Boilers	Gas	0	25%	25%	75%	75%	AP-42 Table 1.4-2 (USEPA 2009)
Generator	Diesel	0	86%	87%	14%	13%	AP-42 Table 3.4-2 (USEPA 2009)
Generator	Gas	0	49%	49%	51%	51%	AP-42 Table 3.2-3 (USEPA 2009)
Pump	Diesel	0	86%	87%	14%	13%	AP-42 Table 3.4-2 (USEPA 2009)
Pump	Gas	0	49%	49%	51%	51%	AP-42 Table 3.2-3 (USEPA 2009)
Flares	Gas	0	25%	25%	75%	75%	AP-42 Table 1.4-2 (pilot/purge fuel gas, assumed as external combustion source) (USEPA 2009)
Cooling Tower	N/A	0	0%	0%	100%	100%	The particulates from cooling towers are hygroscopic particles which are likely organic - therefore assumed 100% SOA.

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10.2 EMISSIONS DATA FOR FAR-FIELD IMPACT ANALYSES

PSD Applicability determinations required dispersion modeling to evaluate Liquefaction Facility impacts at Class I areas located within 300 kilometers of the facility, including air quality and AQRVs (visibility, acid deposition, impacts to soils and vegetation). It is also anticipated that Federal Land Managers (FLMs) will request additional modeling to evaluate the impacts of these facilities, as well as those of other existing sources and reasonably foreseeable future developments, at several Class II areas that are considered by these agencies to be potentially sensitive to air quality and related impacts from the Project facility.

The Class I and Class II areas for which Liquefaction Facility impacts were modeled:

- Denali National Park and Preserve (Class I)
- Tuxedni National Wildlife Refuge (Class I)
- Kenai National Wildlife Refuge (Class II)
- Lake Clark National Park and Preserve (Class II)
- Kenai Fjords National Park (Class II)
- Chugach State Park (Class II)
- Kodiak National Wildlife Refuge (Class II)

10.2.1 Emissions Databases to Support Far-Field Modeling

Far-field modeling to evaluate cumulative impacts at the Class I and Class II areas identified in the previous section involved searches of emissions databases compiled by National Emissions Inventory (NEI) and ADEC, as described in the following subsections. The NEI database (NEI 2011) was used to compile all active facilities near the proposed project locations, while the ADEC Point Source (ADEC 2011) reports provided detailed actual emissions data specific to those facilities that have been identified as potential contributors to the cumulative impacts of the proposed facility.

10.2.1.1 NEI Database

The NEI is a comprehensive and detailed inventory of air emissions for criteria pollutants and precursors, as well as hazardous air pollutants, from stationary air emissions sources. Sources in the NEI include large industrial facilities and electric power plants, airports, and smaller industrial, non-industrial and commercial facilities. A small number of portable sources such as some asphalt and rock crushing operations are also included. The NEI database for a given year includes actual emissions for all criteria pollutants in tons per year, modeled stack parameters and coordinates for all point sources. The most recent available inventory for Alaska was compiled for calendar year 2011. This database was the primary resource available for identifying off-site emission sources to be included in the far-field modeling analyses for the Liquefaction Facility.

10.2.1.2 ADEC Point Source Database

The ADEC is required by Federal Regulation 40 CFR 51.30 to submit an annual statewide point-source emission inventory report to USEPA. This report is required to include all sources with potential emissions at or above one of the following thresholds: 2,500 tons per year of SO_x, NO_x, or CO or 250 tons per year of VOC, PM₁₀, or PM_{2.5}. This database (ADEC 2011) was used in combination with the NEI database to ensure that all potentially significant sources are included.

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10.2.2 Identifying Off-Site Sources

A computer program was used to search the 2011 NEI database (NEI 2011) for Alaska. Any source located within 300 km of a Class I or Class II area receptor and inside the modeling domain was included. The boundary of the modeling domain was defined by pre-developed meteorological datasets that have been accepted for modeling for the area within Alaska that contain the proposed Liquefaction Facility sites.

In order to screen this inventory to remove sources too small to impact the cumulative analysis, a Q/d analysis was conducted following the FLAG 2010 guidance (NPS 2010) on all of the sources previously identified. The total facility emissions (Q) in tons were obtained by adding together the annual emissions for the three main criteria pollutants specified by FLAG 2010: NO_x, SO₂, and PM₁₀. The Q/d guideline specifies the use of maximum short-term PTE level emissions for this purpose. Since the NEI database only contains actual emissions, these facility totals were doubled to approximate PTE levels. Note that FLAG 2010 also specifies that H₂SO₄ emissions should be added to the total facility emissions for the Q/d calculation. The NEI Database PM emissions data are presented as primary PM₁₀ (PM10-PRI), which was assumed to include both the filterable and condensable particulate matter fractions, which would include the conversion of the SO₂ to H₂SO₄.

The distances (d) between point sources and the Class I and II locations in kilometers were provided by a computer program and were supplemented by using the Google Earth measurement tool, as needed. The distances for each facility were determined by taking the closest distance from the individual facility's point sources to the Class I/II location.

Finally, the total annual emissions for each source facility in tons were divided by the corresponding average distance in kilometers to obtain a Q/d value. Using thresholds identified in the FLAG 2010 guidance (NPS 2010), only facilities with a Q/d value or equal to or greater than 10 were included in the final offsite source inventory for far-field modeling.

10.2.3 Modeling Representation of Off-Site Sources

Facilities close to the Liquefaction facilities were modeled as point sources for the near-field modeling (see **Sections 10.1**), and were also included as point sources in the far-field modeling. The additional sources that were added by means of the Q/d analysis described in the previous section, were modeled as volume sources for simplicity and consistency. This representation, which used emission totals over all emission units within a given facility, was necessary to prevent an excessive number of individual stack sources in the far-field simulations.

10.2.3.1 Point Source Modeling Parameters

As described previously, offsite sources within 50 km of the Project facility were included in the near-field (AERMOD) impact assessment and were modeled as point sources at either their PTE emissions or actual emission rates. These sources also carried the same point source representations into the far-field (CALMET/CALPUFF) modeling analysis with the more distant sources from the Q/d screening.

All off-site sources in the far-field modeling were represented by actual emissions, rather than PTE, as is now allowed by USEPA according to recently proposed revisions to the Appendix W modeling guidelines (USEPA 2011).

Particulate matter speciation for these point sources in the AQRV modeling was based on individual equipment type/size and corresponding filterable/condensable PM_{10/2.5} splits consistent with those previously described for the near-field off-site inventory (**Table 10-1**).

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10.2.3.2 Volume Source Modeling Parameters

Far-field off-site sources were modeled as volume sources as previously described. The actual criteria pollutant emissions for a particular facility were represented as the summation over all contributing point sources, as obtained from the NEI Database (NEI 2011) (not doubled as in the Q/d analysis).

For conservatism with respect to the predicted visibility impacts, all filterable particulate matter, including that from non-combustion sources, was treated as elemental carbon, and all condensable particulate matter was treated as secondary organic aerosols. The NEI Database (NEI 2011) includes information on filterable PM₁₀, filterable PM_{2.5} and condensable PM for all listed Alaska sources, except the Ted Stevens Airport in Anchorage. This facility was included in the far-field impacts analysis for the Liquefaction Facility. For this airport, the Total PM (PM₁₀-PRI and PM_{2.5}-PRI) was assumed to result from equal parts of mobile diesel sources, diesel generators, gas-fired heaters, and diesel-fired heaters. AP-42 PM speciation data was used for the stationary sources, and emission factors were derived from the MOVES emissions model for the airport's mobile diesel sources.

In far-field modeling for the Liquefaction Facility, the ARM2 method, which does not rely on stack-specific ratios, was used to estimate NO₂ impacts.

For consistency, all volume sources were given the same source dimensions of 10 meters wide, by 10 meters long, and 10 meters in height, as shown in **Table 10-2**. The Sigma-Y and Sigma-Z dimensions are based on a modeling approach that assigns the initial lateral dimension (Sigma-Y) to the length of the side divided by 4.3 and the initial vertical dimension (Sigma-Z) as the height divided by 4.3 also, if the elevated source is not adjacent to a building.

Table 10-2 Far-Field Modeling Volume Source Dimensions

RELEASE HEIGHT (M)	SIGMA-Y (M)	SIGMA-Z (M)
10	2.33	2.33

Sigma-y and sigma-z are measures of the volume source's horizontal and vertical dimensions.

10.2.3.3 Model Parameters for Reasonably Foreseeable Development (RFD)

In order to ensure that potential impacts in the Class I and Class II areas were fully addressed, ADEC was contacted regarding other new projects throughout the state that are currently engaged in the permitting process or in construction, and may become operational over the next several years. Lists of such projects were provided by ADEC for the modeling domain containing the Project's Liquefaction Facility. Information on the corresponding emissions was obtained from permit documents available on the ADEC website (ADEC 2015). Specifically, maximum allowable (PTE) emissions totaled over all emitting equipment at a new facility were used. The same Q/d analysis described above for existing sources was also used for the RFD sources to screen out those for which projected emissions are below a level of concern. Projects exceeding the Q/d criteria were represented as volume sources with the dimensions described in the previous section. The conservative USEPA (USEPA 2011) default NO₂/NO_x ratio of 0.5 was used for all these future sources in the modeling to estimate NO₂.

In Appendix L – Cumulative Impacts of Resource Report #1, Table 1 provides a list of RFDs to be considered in assessing cumulative environmental impacts of the AKLNG facilities. For each identified project, publicly available information was used to provide a brief description of the activity, as well as a "timeframe for construction and operation, location, footprint, and potential resource impacts that would need to be considered in conjunction with Project resource impacts." Air quality is listed as a potentially affected resource for nearly all of the listed projects since at least some emissions of air pollutants would occur during construction, operations or both.

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However, not all of the projects listed in Table 1 of Appendix L were included in the long-range cumulative modeling. Reasons for excluding specific projects from the far-field modeling analysis are described below:

- Many of the projects are scheduled for completion by 2014 or 2015. By using the available historical air quality monitoring data to establish background concentrations for the area, the cumulative analysis included the contributions of these sources without explicitly modeling them.
- Some of the projects will be at a considerable distance from the proposed Liquefaction Facility location, or constitute a minor modification of an existing facility that would introduce minimal incremental emissions. These two factors would result in very small Q/d values that would screen out such projects from the modeling. (See **Section 10.2.2**)
- Many of the projects are currently only at the conceptual and/or study phase, such that the parameters needed for a meaningful estimation of emissions are insufficiently defined.

Additionally, the long-range modeling included a few RFDs that were not identified in the Appendix L list. As noted above, the final list of RFDs for the modeling analysis was developed in direct discussions with ADEC.

10.2.4 Final Offsite Sources with Emissions

The emissions from the offsite sources used for the near field and far-field modeling are shown in Sections EC-12.

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11.0 ACRONYMS AND TERMS

AAAQS	Alaska Ambient Air Quality Standards
ADEC	Alaska Department of Environmental Conservation
ARM2	Ambient Ratio Method 2
BTU	British Thermal Unit
CH ₄	Methane
CO	Carbon Monoxide
CO ₂	Carbon Dioxide
FERC	Federal Energy Regulatory Commission
FLAG	Federal Land Managers' Air Quality Related Values Work Group
FLM	Federal Land Manager
GHG	Greenhouse Gas
GTP	Gas Treatment Plant
HAP	Hazardous Air Pollutant
HP	High Pressure
HRSG	Heat Recovery Stream Generator
IC	Internal Combustion
IMO	International Maritime Organization
LNG	Liquefied Natural Gas
lb/hr	Pounds per hour
LP	Low pressure
MM	Million
MMSCFD	Million Standard Cubic Feet per Day
NAAQS	National Ambient Air Quality Standards
N ₂ O	Nitrous Oxide
NO ₂	Nitrogen Dioxide
NO _x	Nitrogen Oxides
Pb	Lead
PBU	Prudhoe Bay Unit
PM _{2.5}	Particulate matter having an aerodynamic diameter of 2.5 microns or less
PM ₁₀	Particulate matter having an aerodynamic diameter of 10 microns or less
PMF	Particulate Matter Fine – from non-combustion sources
ppmv	Parts per million by volume
Project	Alaska LNG Project
PSD	Prevention of Significant Deterioration
PTU	Point Thomson Unit
RICE	Reciprocating Internal Combustion Engine
SF	Supplemental Firing
SO ₂	Sulfur Dioxide
tpy	Tons per Year
USEPA	U.S. Environmental Protection Agency
VOC	Volatile Organic Compounds
WHRU	Waste Heat Recovery Unit

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EC-1 LIQUEFACTION FACILITY POTENTIAL TO EMIT SUMMARY

Model ID	Source Description	Annual Operating Hours	Potential to Emit (PTE) Emission Rates																							
			NO _x		CO			VOC		PM ₁₀			PM _{2.5}			SO ₂ @ 16 ppmvd			CO ₂	CH ₄	N ₂ O	CO ₂ e	HAPs (Formaldehyde)		HAPs (Total)	
			lb/hr	tpy	lb/hr	lb/8-hr	tpy	lb/hr	tpy	lb/hr	lb/day	tpy	lb/hr	lb/day	tpy	lb/hr	lb/day	tpy	tonnes/yr	tonnes/yr	tonnes/yr	tonnes/yr	lb/hr	tpy	lb/hr	tpy
TURB1	Train 1a Compression Turbine Stack	8760	37.64	156.74	63.65	509.20	265.05	2.62	10.91	8.23	197.50	34.29	8.23	197.50	34.29	2.92	70.00	12.15	517328.63	9.75	0.97	517862.93	0.79	3.46	1.14	5.01
TURB2	Train 1b Compression Turbine Stack	8760	37.64	156.74	63.65	509.20	265.05	2.62	10.91	8.23	197.50	34.29	8.23	197.50	34.29	2.92	70.00	12.15	517328.63	9.75	0.97	517862.93	0.79	3.46	1.14	5.01
TURB3	Train 2a Compression Turbine Stack	8760	37.64	156.74	63.65	509.20	265.05	2.62	10.91	8.23	197.50	34.29	8.23	197.50	34.29	2.92	70.00	12.15	517328.63	9.75	0.97	517862.93	0.79	3.46	1.14	5.01
TURB4	Train 2b Compression Turbine Stack	8760	37.64	156.74	63.65	509.20	265.05	2.62	10.91	8.23	197.50	34.29	8.23	197.50	34.29	2.92	70.00	12.15	517328.63	9.75	0.97	517862.93	0.79	3.46	1.14	5.01
TURB5	Train 3a Compression Turbine Stack	8760	37.64	156.74	63.65	509.20	265.05	2.62	10.91	8.23	197.50	34.29	8.23	197.50	34.29	2.92	70.00	12.15	517328.63	9.75	0.97	517862.93	0.79	3.46	1.14	5.01
TURB6	Train 3b Compression Turbine Stack	8760	37.64	156.74	63.65	509.20	265.05	2.62	10.91	8.23	197.50	34.29	8.23	197.50	34.29	2.92	70.00	12.15	517328.63	9.75	0.97	517862.93	0.79	3.46	1.14	5.01
TRB_GEN1	Power Generator Turbines	8760	14.61	52.89	7.91	63.27	17.89	0.97	3.76	3.05	73.09	11.83	3.05	73.09	11.83	1.08	25.88	4.19	178485.35	3.36	0.34	178669.69	0.27	1.19	0.39	1.73
TRB_GEN2	Power Generator Turbines	8760	14.61	52.89	7.91	63.27	17.89	0.97	3.76	3.05	73.09	11.83	3.05	73.09	11.83	1.08	25.88	4.19	178485.35	3.36	0.34	178669.69	0.27	1.19	0.39	1.73
TRB_GEN3	Power Generator Turbines	8760	14.61	52.89	7.91	63.27	17.89	0.97	3.76	3.05	73.09	11.83	3.05	73.09	11.83	1.08	25.88	4.19	178485.35	3.36	0.34	178669.69	0.27	1.19	0.39	1.73
TRB_GEN4	Power Generator Turbines	8760	14.61	52.89	7.91	63.27	17.89	0.97	3.76	3.05	73.09	11.83	3.05	73.09	11.83	1.08	25.88	4.19	178485.35	3.36	0.34	178669.69	0.27	1.19	0.39	1.73
Aux_COMP	Auxiliary Air Compressor (224 kW)	500	0.25	0.06	2.16	17.26	0.54	0.12	0.03	0.01	0.30	3.08E-03	0.01	0.30	0.00	0.00	0.07	7.33E-04	77.66	0.00	0.00	77.92	0.00	0.00	0.01	2.12E-03
FPUMP	Firewater Pump (429 kW)	500	4.52	1.13	4.12	32.96	1.03	0.24	0.06	0.24	5.70	0.06	0.24	5.70	0.06	0.01	0.13	1.40E-03	148.84	0.01	0.00	149.36	0.00	0.00	0.02	4.07E-03
FLARE_1D	Dry Flare Pilot/Purge	8760	0.49	2.13	2.22	17.73	9.71	4.08	17.85	0.20	4.84	0.88	0.20	4.84	0.88	0.02	0.41	0.08	3323.36	0.06	0.01	3326.79	0.01	0.04	0.02	0.09
FLARE_2D	Dry Flare Pilot/Purge	8760	0.49	2.13	2.22	17.73	9.71	4.08	17.85	0.20	4.84	0.88	0.20	4.84	0.88	0.02	0.41	0.08	3323.36	0.06	0.01	3326.79	0.01	0.04	0.02	0.09
	Dry Flare Pilot/Purge (Not Modeled)	8760																								
FLARE_1W	Wet Flare Pilot/Purge	8760	0.15	0.67	0.70	5.58	3.06	1.28	5.62	0.06	1.52	0.28	0.06	1.52	0.28	0.01	0.14	0.02	1045.81	0.02	0.00	1046.89	0.00	0.01	0.01	0.03
FLARE_2W	Wet Flare Pilot/Purge	8760	0.15	0.67	0.70	5.58	3.06	1.28	5.62	0.06	1.52	0.28	0.06	1.52	0.28	0.01	0.14	0.02	1045.81	0.02	0.00	1046.89	0.00	0.01	0.01	0.03
	Wet Flare Pilot/Purge (Not Modeled)	8760																								
DRY_MAX1	Dry Flare Maximum Case	500	2039.73	1019.86	9298.76	9298.76	4649.38	17097.72	8548.86	846.49	846.49	423.25	846.49	846.49	423.25	74.75	74.75	37.38	1591587.76	30.00	3.00	1593231.54	34.38	17.19	86.90	43.45
DRY_MAX2	Dry Flare Maximum Case	500	2039.73	1019.86	9298.76	9298.76	4649.38	17097.72	8548.86	846.49	846.49	423.25	846.49	846.49	423.25	74.75	74.75	37.38	1591587.76	30.00	3.00	1593231.54	34.38	17.19	86.90	43.45
	Dry Flare Maximum Case (Not Modeled)	500																								
WET_MAX1	Wet Flare Maximum Case	500	476.68	238.34	2173.10	2173.10	1086.55	3995.70	1997.85	197.82	197.82	98.91	197.82	197.82	98.91	17.48	17.48	8.74	371950.60	7.01	0.70	372334.75	8.03	4.02	20.31	10.15
WET_MAX2	Wet Flare Maximum Case	500	476.68	238.34	2173.10	2173.10	1086.55	3995.70	1997.85	197.82	197.82	98.91	197.82	197.82	98.91	17.48	17.48	8.74	371950.60	7.01	0.70	372334.75	8.03	4.02	20.31	10.15
	Wet Flare Maximum Case (Not Modeled)	500																								
LP_FLARE	LP Flare Pilot/Purge	8760	0.71	3.13	3.26	26.04	14.26	5.99	26.21	0.30	7.11	1.30	0.30	7.11	1.30	0.05	1.21	0.22	4880.46	0.09	0.01	4885.50	0.01	0.05	0.03	0.13
LP_MAX	LP Flare Maximum Flow (Maintenance)	144	71.37	5.14	311.38	2491.02	22.42	568.58	40.94	28.15	675.59	2.03	28.15	675.59	2.03	2.74	65.72	0.20	7621.54	0.14	0.01	7629.41	1.14	0.08	2.89	0.21
TH_OX	Thermal Oxidizer	8760	0.60	2.63	0.49	3.96	2.17	0.03	0.14	0.04	1.07	0.20	0.04	1.07	0.20	0.02	0.39	0.07	2793.48	0.05	0.01	2796.37	0.00	0.00	0.01	0.05
	Tank Emissions	8760																								
	Fugitive Emissions	8760						4.10	17.96											96.95		2,424				
	Mobile Equipment Emissions (Normal Operation)	8760		3.26			3.26		0.33			0.19			0.17			0.02	2,160	0.13	0	2,165				0
	Non-Road/Portable Equipment Emissions (Normal Operation)	8760		7.59			3.22		2.43			0.69			0.69											
	Marine Terminal Emissions (Normal Operation)	8760	279.31	379.59	457.69	3661.53	630.38	59.17	116.58	13.33	319.84	14.01	12.26	294.18	12.98	18.28	438.81	1.17				81247.80			0.31	0.33
Total Emissions (Without Maximum Flare)			642.3	1,560.1	1,198.5	9,587.7	2,364.6	668.5	332.1	104.2	2,499.7	273.9	103.1	2,474.1	272.8	43.0	1,030.9	91.5	3,844,333.2	169.5	7.3	3,931,979.3	7.0	25.8	11.8	38.0
Total Emissions (With Maximum Flare)			5,675.1	4,076.5	24,142.2	32,531.4	13,836.5	42,855.4	21,425.6	2,192.8	4,588.4	1,318.2	2,191.7	4,562.7	1,317.1	227.4	1,215.4	183.8	7,771,409.9	243.5	14.7	7,863,111.9	91.8	68.2	226.2	145.2

8 CO Standard Requirement
24 Intermittent unit hours/day operation
24 Non-intermittent unit hours/day operation
0.5 Flare hours/day operation

EC-2 LIQUEFACTION FACILITY MODELED EMISSIONS SUMMARY

Modeled ID	Emission Unit	Configuration	Coordinates (UTM)		Base Elevation (m)	Modeled Height		Temperature		Velocity		Diameter		In-Stack Ratio (-)	NOx			CO		PM ₁₀		PM _{2.5}		SO ₂ @16 ppmvd			
			x	y		(ft)	(m)	(°F)	(°K)	(ft/s)	(m/s)	(ft)	(m)		1-hour	24-hour	Annual	1-hour	8-hour	24-hour	Annual	24-hour	Annual	1-hour	3&24-hour	Annual	
Turbines																											
TURB1	Train 1a Compression Turbine Stack	Vert./no Cap	589612.04	6726290.1	38.0	210.00	64.01	970.00	794.26	86.00	26.21	19.00	5.79	0.50	4.74E+00	4.74E+00	4.51E+00	8.02E+00	8.02E+00	1.04E+00	9.86E-01	1.04E+00	9.86E-01	3.67E-01	3.67E-01	3.50E-01	
TURB2	Train 1b Compression Turbine Stack	Vert./no Cap	589704.73	6726354	38.0	210.00	64.01	970.00	794.26	86.00	26.21	19.00	5.79	0.50	4.74E+00	4.74E+00	4.51E+00	8.02E+00	8.02E+00	1.04E+00	9.86E-01	1.04E+00	9.86E-01	3.67E-01	3.67E-01	3.50E-01	
TURB3	Train 2a Compression Turbine Stack	Vert./no Cap	589477.15	6726485.3	38.0	210.00	64.01	970.00	794.26	86.00	26.21	19.00	5.79	0.50	4.74E+00	4.74E+00	4.51E+00	8.02E+00	8.02E+00	1.04E+00	9.86E-01	1.04E+00	9.86E-01	3.67E-01	3.67E-01	3.50E-01	
TURB4	Train 2b Compression Turbine Stack	Vert./no Cap	589570.16	6726549.4	38.0	210.00	64.01	970.00	794.26	86.00	26.21	19.00	5.79	0.50	4.74E+00	4.74E+00	4.51E+00	8.02E+00	8.02E+00	1.04E+00	9.86E-01	1.04E+00	9.86E-01	3.67E-01	3.67E-01	3.50E-01	
TURB5	Train 3a Compression Turbine Stack	Vert./no Cap	589343.13	6726679.9	38.0	210.00	64.01	970.00	794.26	86.00	26.21	19.00	5.79	0.50	4.74E+00	4.74E+00	4.51E+00	8.02E+00	8.02E+00	1.04E+00	9.86E-01	1.04E+00	9.86E-01	3.67E-01	3.67E-01	3.50E-01	
TURB6	Train 3b Compression Turbine Stack	Vert./no Cap	589435.88	6726744.2	38.0	210.00	64.01	970.00	794.26	86.00	26.21	19.00	5.79	0.50	4.74E+00	4.74E+00	4.51E+00	8.02E+00	8.02E+00	1.04E+00	9.86E-01	1.04E+00	9.86E-01	3.67E-01	3.67E-01	3.50E-01	
TRB_GEN1	Power Generator Turbines	Vert./no Cap	589851.09	6726009.6	38.0	150.00	45.72	341.00	444.82	48.00	14.63	10.00	3.05	0.50	1.84E+00	1.84E+00	1.52E+00	9.96E-01	9.96E-01	3.84E-01	3.40E-01	3.84E-01	3.40E-01	1.36E-01	1.36E-01	1.21E-01	
TRB_GEN2	Power Generator Turbines	Vert./no Cap	589931.34	6726064.9	38.0	150.00	45.72	341.00	444.82	48.00	14.63	10.00	3.05	0.50	1.84E+00	1.84E+00	1.52E+00	9.96E-01	9.96E-01	3.84E-01	3.40E-01	3.84E-01	3.40E-01	1.36E-01	1.36E-01	1.21E-01	
TRB_GEN3	Power Generator Turbines	Vert./no Cap	590011.59	6726120.3	38.0	150.00	45.72	341.00	444.82	48.00	14.63	10.00	3.05	0.50	1.84E+00	1.84E+00	1.52E+00	9.96E-01	9.96E-01	3.84E-01	3.40E-01	3.84E-01	3.40E-01	1.36E-01	1.36E-01	1.21E-01	
TRB_GEN4	Power Generator Turbines	Vert./no Cap	590091.83	6726175.8	38.0	150.00	45.72	341.00	444.82	48.00	14.63	10.00	3.05	0.50	1.84E+00	1.84E+00	1.52E+00	9.96E-01	9.96E-01	3.84E-01	3.40E-01	3.84E-01	3.40E-01	1.36E-01	1.36E-01	1.21E-01	
Diesel Equipment																											
Aux_COMP	Auxiliary Air Compressor (224 kW) ¹	Vert./no Cap	589576.44	6726013.5	38.0	10.00	3.05	883.00	745.93	115.00	35.05	0.67	0.20	0.50	1.77E-03	3.11E-02	1.77E-03	2.72E-01	2.72E-01	1.55E-03	8.87E-05	1.55E-03	8.87E-05	2.11E-05	3.69E-04	2.11E-05	
FPUMP	Firewater Pump (429 kW) ¹	Vert./no Cap	590146.73	6726056.2	38.0	10.00	3.05	908.00	759.82	157.00	47.85	0.67	0.20	0.50	3.25E-02	5.69E-01	3.25E-02	5.19E-01	5.19E-01	2.99E-02	1.71E-03	2.99E-02	1.71E-03	4.04E-05	7.08E-04	4.04E-05	
Flares																											
FLARE_1D	Dry Flare Pilot/Purge	Vert./no Cap	589999.69	6725837.1	38.0	7.56	2.30	1831.73	1273.00	65.62	20.00	1.46	0.45	0.50	6.13E-02	6.13E-02	6.13E-02	2.79E-01	2.79E-01	2.54E-02	2.54E-02	2.54E-02	2.54E-02	2.17E-03	2.17E-03	2.17E-03	
FLARE_2D	Dry Flare Pilot/Purge	Vert./no Cap	590097.74	6725906.3	38.0	7.56	2.30	1831.73	1273.00	65.62	20.00	1.46	0.45	0.50	6.13E-02	6.13E-02	6.13E-02	2.79E-01	2.79E-01	2.54E-02	2.54E-02	2.54E-02	2.54E-02	2.17E-03	2.17E-03	2.17E-03	
FLARE_1W	Wet Flare Pilot/Purge	Vert./no Cap	589999.69	6725837.1	38.0	4.35	1.32	1831.73	1273.00	65.62	20.00	0.82	0.25	0.50	1.93E-02	1.93E-02	1.93E-02	8.79E-02	8.79E-02	8.00E-03	8.00E-03	8.00E-03	8.00E-03	7.09E-04	7.09E-04	7.09E-04	
FLARE_2W	Wet Flare Pilot/Purge	Vert./no Cap	590097.74	6725906.3	38.0	4.35	1.32	1831.73	1273.00	65.62	20.00	0.82	0.25	0.50	1.93E-02	1.93E-02	1.93E-02	8.79E-02	8.79E-02	8.00E-03	8.00E-03	8.00E-03	8.00E-03	7.09E-04	7.09E-04	7.09E-04	
DRY_MAX1	Dry Flare Maximum Case ¹	Vert./no Cap	589999.69	6725837.1	38.0	567.00	172.82	1831.73	1273.00	65.62	20.00	133.98	40.84	0.50	2.93E+01	1.07E+01	2.93E+01	1.17E+03	1.46E+02	4.44E+00	1.22E+01	4.44E+00	1.22E+01	1.08E+00	3.14E+00	1.08E+00	
DRY_MAX2	Dry Flare Maximum Case ¹	Vert./no Cap	590097.74	6725906.3	38.0	567.00	172.82	1831.73	1273.00	65.62	20.00	133.98	40.84	0.50	2.93E+01	1.07E+01	2.93E+01	1.17E+03	1.46E+02	4.44E+00	1.22E+01	4.44E+00	1.22E+01	1.08E+00	3.14E+00	1.08E+00	
WET_MAX1	Wet Flare Maximum Case ¹	Vert./no Cap	589999.69	6725837.1	38.0	283.14	86.30	1831.73	1273.00	65.62	20.00	64.80	19.75	0.50	6.86E+00	2.50E+00	6.86E+00	2.74E+02	3.42E+01	1.04E+00	2.85E+00	1.04E+00	2.85E+00	2.51E-01	7.34E-01	2.51E-01	
WET_MAX2	Wet Flare Maximum Case ¹	Vert./no Cap	590097.74	6725906.3	38.0	283.14	86.30	1831.73	1273.00	65.62	20.00	64.80	19.75	0.50	6.86E+00	2.50E+00	6.86E+00	2.74E+02	3.42E+01	1.04E+00	2.85E+00	1.04E+00	2.85E+00	2.51E-01	7.34E-01	2.51E-01	
LP_FLARE	LP Flare Pilot/Purge	Vert./no Cap	589339.8	6726051.8	38.0	208.08	63.42	1831.73	1273.00	65.62	20.00	1.77	0.54	0.50	9.00E-02	9.00E-02	9.00E-02	4.10E-01	4.10E-01	3.73E-02	3.73E-02	3.73E-02	3.73E-02	6.36E-03	6.36E-03	6.36E-03	
LP_MAX	LP Flare Maximum Flow ¹ (Maintenance)	Vert./no Cap	589339.8	6726051.8	38.0	278.94	85.02	1831.73	1273.00	65.62	20.00	17.26	5.26	0.50	1.48E-01	8.99E+00	1.48E-01	3.92E+01	3.92E+01	3.55E+00	5.83E-02	3.55E+00	5.83E-02	5.67E-03	3.45E-01	5.67E-03	
TH_OX	Thermal Oxidizer	Vert./no Cap	589545.89	6725947.9	38.0	47.00	14.33	1800.00	1255.37	8.90	2.71	5.00	1.52	0.50	7.57E-02	7.57E-02	7.57E-02	6.24E-02	6.24E-02	5.64E-03	5.64E-03	5.64E-03	5.64E-03	2.07E-03	2.07E-03	2.07E-03	
Total Emissions (Without Maximum Flare)															36.33	45.74	33.65	93.33	93.33	11.44	7.45	11.44	7.45	2.77	3.11	2.60	
Total Emissions (With Maximum Flare)															108.72	72.16	106.04	2984.18	454.69	22.41	37.49	22.41	37.49	5.42	10.86	5.25	

NOTES

- 500 hours Intermittent Diesel Equipment has been modeled with an annual value based on operating only 500 hours/year.
- 500 hours Maximum Flaring Events have been modeled with an annual value based on operating only 500 hours/year.
- 144 hours Maximum LP Flaring Events have been modeled with an annual value based on operating only 144 hours/year.
- 8,760 hours Annual hours
- 0.5 hours Per day maximum flare operation

1 Intermittent equipment 1-hr NOx and SO2 emissions can be annualized

Modeled ID	Emission Unit	Equip Type	Fuel Type	PMF/SOIL	EC - PM2.5	EC - PM10	SOA - PM2.5	SOA - PM10
				g/s	g/s	g/s	g/s	g/s
Turbines								
TURB1	Train 1a Compression Turbine Stack	Turbine	Gas	0.000E+00	2.985E-01	2.985E-01	7.384E-01	7.384E-01
TURB2	Train 1b Compression Turbine Stack	Turbine	Gas	0.000E+00	2.985E-01	2.985E-01	7.384E-01	7.384E-01
TURB3	Train 2a Compression Turbine Stack	Turbine	Gas	0.000E+00	2.985E-01	2.985E-01	7.384E-01	7.384E-01
TURB4	Train 2b Compression Turbine Stack	Turbine	Gas	0.000E+00	2.985E-01	2.985E-01	7.384E-01	7.384E-01
TURB5	Train 3a Compression Turbine Stack	Turbine	Gas	0.000E+00	2.985E-01	2.985E-01	7.384E-01	7.384E-01
TURB6	Train 3b Compression Turbine Stack	Turbine	Gas	0.000E+00	2.985E-01	2.985E-01	7.384E-01	7.384E-01
TRB_GEN1	Power Generator Turbines	Turbine	Gas	0.000E+00	1.105E-01	1.105E-01	2.733E-01	2.733E-01
TRB_GEN2	Power Generator Turbines	Turbine	Gas	0.000E+00	1.105E-01	1.105E-01	2.733E-01	2.733E-01
TRB_GEN3	Power Generator Turbines	Turbine	Gas	0.000E+00	1.105E-01	1.105E-01	2.733E-01	2.733E-01
TRB_GEN4	Power Generator Turbines	Turbine	Gas	0.000E+00	1.105E-01	1.105E-01	2.733E-01	2.733E-01
Diesel Equipment								
Aux_COMP	Auxiliary Air Compressor (224 kW) ¹	Compressor	Diesel	0.000E+00	1.338E-03	1.345E-03	2.151E-04	2.088E-04
FPUMP	Firewater Pump (429 kW) ¹	Pump	Diesel	0.000E+00	2.580E-02	2.592E-02	4.147E-03	4.024E-03
Flares								
FLARE_1D	Dry Flare Pilot/Purge	Flare	Gas	0.000E+00	6.356E-03	6.356E-03	1.907E-02	1.907E-02
FLARE_2D	Dry Flare Pilot/Purge	Flare	Gas	0.000E+00	6.356E-03	6.356E-03	1.907E-02	1.907E-02
FLARE_1W	Wet Flare Pilot/Purge	Flare	Gas	0.000E+00	2.000E-03	2.000E-03	6.000E-03	6.000E-03
FLARE_2W	Wet Flare Pilot/Purge	Flare	Gas	0.000E+00	2.000E-03	2.000E-03	6.000E-03	6.000E-03
DRY_MAX1	Dry Flare Maximum Case ¹	Flare	Gas	0.000E+00	1.111E+00	1.111E+00	3.333E+00	3.333E+00
DRY_MAX2	Dry Flare Maximum Case ¹	Flare	Gas	0.000E+00	1.111E+00	1.111E+00	3.333E+00	3.333E+00
WET_MAX1	Wet Flare Maximum Case ¹	Flare	Gas	0.000E+00	2.596E-01	2.596E-01	7.789E-01	7.789E-01
WET_MAX2	Wet Flare Maximum Case ¹	Flare	Gas	0.000E+00	2.596E-01	2.596E-01	7.789E-01	7.789E-01
LP_FLARE	LP Flare Pilot/Purge	Flare	Gas	0.000E+00	9.334E-03	9.334E-03	2.800E-02	2.800E-02
LP_MAX	LP Flare Maximum Flow ¹ (Maintenance)	Flare	Gas	0.000E+00	8.867E-01	8.867E-01	2.660E+00	2.660E+00
TH_OX	Thermal Oxidizer	Heater	Gas	0.000E+00	1.411E-03	1.411E-03	4.232E-03	4.232E-03
Total Emissions (Without Maximum Flare)								
Total Emissions (With Maximum Flare)								

NOTES

- 500 hours Intermittent Diesel Equipment has been modeled with an annual value based on operating only 500 hours/year.
- 500 hours Maximum Flaring Events have been modeled with an annual value based on operating only 500 hours/year.
- 144 hours Maximum LP Flaring Events have been modeled with an annual value based on operating only 144 hours/year.
- 8,760 hours Annual hours
- 0.5 hours Per day maximum flare operation

1 Intermittent equipment 1-hr NOx and SO2 emissions can be annualized

EC-3 LIQUEFACTION FACILITY FUEL SPECIFICATIONS

LNG Fuel Gas Specification		
Component	% By Volume	MW
N ₂ - Nitrogen	0.6872	
CO ₂ - Carbon Dioxide	0.005	
H ₂ O - Water		
O ₂ - Oxygen	0.001	
Ar - Argon		
H ₂ - Hydrogen		
CH ₄ - Methane	91.1475	
C ₂ H ₆ - Ethane	5.8251	
C ₃ H ₈ - Propane	1.8872	
C ₄ H ₁₀ - IsoButane	0.1374	
C ₄ H ₁₀ - Normal Butane	0.2056	
C ₅ H ₁₂ - IsoPentane	0.0463	
C ₅ H ₁₂ - N-Pentane	0.0443	
C ₆ H ₁₄ - 2-Methylpentane	0.0017	
C ₆ H ₁₄ - Hexane	0.0023	
C ₆ H ₁₂ -Methylcyclopentane	0.0013	
C ₆ H ₁₂ - Cyclohexane	0.0012	
C ₇ H ₁₆ - Heptane	0.0041	
C ₇ H ₁₄ - Methylcyclohexane	0.0011	
C ₈ H ₁₈ - Octane	0.001	
C ₉ H ₂₀ - Nonane	0.0003	
C ₁₀ H ₂₂ - Decane	0.0001	
C ₁₀ H ₁₈ - Heavy Oil		
C ₁₂ H ₂₆ - Distillate		
C ₆ H ₆ - Benzene		
C ₇ H ₈ - Toluene		
C ₈ H ₁₀ - Xylene		
C ₈ H ₈ - Styrene		
Hg - Mercury		
C ₂ H ₄ - Ethylene		
C ₂ H ₂ - Acetylene		
C ₃ H ₆ - Propylene		
C ₄ H ₈ - Butylene		
C ₄ H ₆ - Butadienes		
C ₆ H ₁₂ - Hexene		
CH ₃ OH - Methanol		
C ₂ H ₅ OH - Ethyl Alcohol		
CO - Carbon Monoxide		
NO - Nitric Oxide		
NO ₂ - Nitrogen Dioxide		
NH ₃ - Ammonia		
H ₂ S - Hydrogen Sulfide	0.0016	64.066
COS - Carbonyl Sulfide		
C ₂ H ₆ S ₂ - DiMethyl DiSulfide		
SO ₂		
Properties		
Temp		
MW	17.6800	
Fuel Heating Value at 82°F:		
Net (Btu/lbm)		
Net (Btu/scf)	981.0000	
Gross (Btu/lbm)		
Gross (Btu/scf)	1087.0000	
scf defined at 14.676 psia, 60F		

Notes:

1 Normal maximum sulfur based on 16 ppmv for total sulfur being equal to the pipeline specification of 1 grain/100 scf. This assumes all H2S and other mercaptans are included in Sulfur value

LNG Diesel Fuel Specification				
Sulfur Content (H2S)	15	ppm	Assume ULSD required	
Specific Gravity	0.855		average value at 60oF	
Density	7.1307	lb/gal		
LHV	0.131133573	MMBtu/gal		
LHV	18,390	Btu/lb		
HHV	0.14424693	MMBtu/gal	Assumed 10% higher than LHV	
HHV	20,229	Btu/lb		
lb SO2/gal Fuel	0.000201337			

EC-4 LIQUEFACTION FACILITY FUEL GAS-DRIVEN TURBINES

EMISSION FACTORS	Standard Factors		Special/Vendor						
	AP42 Table 3.1-1 and 3.1-2a	40 CFR Part 98 (Natural Gas)		Ambient Temp Basis (F)	Load % Basis	Compression Turbine Vendor	Ambient Temp Basis (F)	Load % Basis	Power Generation Turbine Vendor
NOx (lb/MMBtu)	0.341		Short-Term ppmvd @ 15% NOx	-30.00	100%	9.00	-30.00	100%	9.00
CO (lb/MMBtu)	0.087		Short-Term ppmvd @ 15% CO	-30.00	100%	25.00	-30.00	100%	8.00
VOC (lb/MMBtu)	0.002		Annual ppmvd @ 15% NOx	40.00	100%	9.00	40.00	100%	9.00
PM10 (lb/MMBtu)	0.007		Annual ppmvd @ 15% CO	40.00	100%	25.00	40.00	100%	5.00
PM2.5 (lb/MMBtu)	0.007								
CO2 (kg CO2/MMBtu)		53.060							
CH4 (kg CH4/MMBtu)		0.001							
N2O (kg N2O/MMBtu)		0.0001							

Notes:

1.) Emission Factors have been convert to AlaskaLNG fuel gas HHV by ratio of project fuel gas/1020 (btu/scf)

EMISSIONS CALCULATIONS	Compressor Turbines		Power Generation Turbines with CO Catalyst and HRSG		References/Comments
Turbine Parameters	Short-Term	Annual	Short-Term	Annual	
Total Installed	6	6	4	4	From CB&I/Chiyoda Calculation
Ambient Temperature Basis (F)	-30	40	-30	40	
Load % Basis	100%	100%	100%	100%	
Operation (hr/yr)	8,760	8,760	8,760	8,760	
Device Power (hp)	155,760	152,876	60,603	53,756	
Device Power (kW)	116,150	114,000	45,192	40,086	From CB&I/Chiyoda Calculation - Output
Turbine Heat Input HHV (MMBtu/hr)	1,170	1,113	433	384	From CB&I/Chiyoda Calculation
Fuel Flow Rate (lbmol/hr)	2,845	2,706	1,052	933	From CB&I/Chiyoda Calculation
Exhaust Flow MW (lb/lbmol)	28.6	28.5	28.51	28.54	From CB&I/Chiyoda Calculation
Exhaust Flow Rate WET (lb/hr)	2,524,290	2,477,111	1,027,143	924,064	From CB&I/Chiyoda Calculation
Exhaust Flow Rate (lbmol/hr)	88,416	86,916	36,027	32,378	
Exhaust H2O Concentration	6.72%	7.10%	6.94%	6.44%	From CB&I/Chiyoda Calculation
Exhaust Flow Rate DRY (lbmol/hr)	82,475	80,745	33,527	30,293	
Exhaust O2 Concentration DRY	14.40%	14.59%	14.7%	15.2%	From CB&I/Chiyoda Calculation
Exhaust Flow Rate (acfh)	92,314,464	90,748,034	21,070,109	18,935,692	

EMISSIONS CALCULATIONS	Compressor Turbines		Power Generation Turbines with CO Catalyst and HRSG		References/Comments
Turbine Emission Factors	Short-Term	Annual	Short-Term	Annual	
NOx (ppmvd @15% O2)	9.00	9.00	9.00	9.00	Adjusted to Actual O2 Amount
CO (ppmvd @15% O2)	25.00	25.00	8.00	5.00	Adjusted to Actual O2 Amount
VOC (lb/MMBtu)	0.002	0.002	0.002	0.002	
PM10 (lb/MMBtu)	0.007	0.007	0.007	0.007	
PM2.5 (lb/MMBtu)	0.007	0.007	0.007	0.007	
SO2	No Emission Factor	No Emission Factor	No Emission Factor	No Emission Factor	Based on Mass Balance of Sulfur
CO2 (kg CO2/MMBtu)	53.060	53.060	53.060	53.060	
CH4 (kg CH4/MMBtu)	0.001	0.001	0.001	0.001	
N2O (kg N2O/MMBtu)	0.0001	0.0001	0.0001	0.0001	
Turbine Emission Calculations (Maximum 1-hour)					
NOx (lb/hr)	37.640	35.784	14.614	12.076	
CO (lb/hr)	63.651	60.513	7.908	4.084	
VOC (lb/hr)	2.618	2.491	0.969	0.859	
PM10 (lb/hr)	8.229	7.828	3.046	2.701	
PM2.5 (lb/hr)	8.229	7.828	3.046	2.701	
SO2 @ 16 ppm (lb/hr)	2.917	2.774	1.078	0.956	
CO2 (lb/hr)	136,862.009	130,194.373	50,650.641	44,918.813	
CH4 (lb/hr)	2.579	2.454	0.955	0.847	
N2O (lb/hr)	0.258	0.245	0.095	0.085	
CO2e (lb/hr)	137,003.359	130,328.836	50,702.953	44,965.205	
Total Emission Calculations (Annual)					
NOx (tpy)	164.861	156.735	64.009	52.892	
CO (tpy)	278.789	265.048	34.638	17.889	
VOC (tpy)	11.469	10.910	4.244	3.764	
PM10 (tpy)	36.044	34.288	13.339	11.830	
PM2.5 (tpy)	36.044	34.288	13.339	11.830	
SO2 @ 16 ppm (tpy)	12.775	12.151	4.723	4.189	
CO2 (tonnes/yr)	543,822.552	517,328.633	201,260.825	178,485.350	
CH4 (tonnes/yr)	10.249	9.750	3.793	3.364	
N2O (tonnes/yr)	1.025	0.975	0.379	0.336	
CO2e (tonnes/yr)	544,384.208	517,862.926	201,468.686	178,669.689	
Stack Parameters					
Stack Height (ft)	210	210	150	150	From CB&I/Chiyoda Calculation
Exhaust Temp Ambient Temp Basis (F)	-30	-30	--	--	
Exhaust Temp Load % Basis	100%	100%	--	--	
Exhaust Temperature (F)	970	970	341	341	From CB&I/Chiyoda Calculation with HRSG
Exhaust Velocity Ambient Temp Basis (F)	71	71	70	70	
Exhaust Velocity Load % Basis	100%	100%	60%	60%	
Exhaust Velocity (ft/s)	86	86	48.00	48.00	From CB&I/Chiyoda Calculation with HRSG adjustment
Stack Diameter (ft)	19	19	10	10	From CB&I/Chiyoda Calculation
NO2/NOx Ratio	0.5	0.5	0.5	0.5	EPA's ISR Guidance (Date: 3-1-2011)

EC-5 LIQUEFACTION FACILITY DIESEL EQUIPMENT

	Emergency				Non-Emergency		
EMISSION FACTORS	Standard Factors						
	40 CFR Part 89.112 Tier 3 130<kW<225	40 CFR Part 89.112 Tier 3 225<kW<450	40 CFR Part 60 Subpart IIII 175<hp<300	40 CFR Part 60 Subpart IIII 300<hp<600	40 CFR 1039 Subpart B Tier 4 130<kW<560	40 CFR 1039 Subpart B Tier 4 kW > 560	40 CFR Part 98 (Petroleum)
NOx (g/hp-hr) (95% of NOx+NMHC)	2.834	2.834	2.850	2.850	0.298	2.610	
CO (g/hp-hr)	2.610	2.610	2.600	2.600	2.610	2.610	
VOC (g/hp-hr) (5% of NOx+NMHC)	0.149	0.149	0.150	0.150	0.142	0.142	
PM10 (g/hp-hr)	0.149	0.149	0.150	0.150	0.015	0.030	
PM2.5 (g/hp-hr)	0.149	0.149	0.150	0.150	0.015	0.030	
CO2 (kg CO2/MMBtu)							73.960
CH4 (kg CH4/MMBtu)							0.003
N2O (kg N2O/MMBtu)							0.001

EMISSIONS CALCULATIONS	Auxiliary Air Compressor	Firewater Pump	References/ Comments
Total Installed	1	1	From CB&I/Chiyoda Calculation
Load	100%	100%	Ambient Temp does not affect emissions
Operation (hr/yr)	500	500	Intermittent Assumption
Rated Power (hp)	300	575	From Chiyoda Calculation
Rated Power (kW)	224	429	From Chiyoda Calculation
BSFC (Btu/hp-hr)	7,000	7,000	AP42 Table 3.3-1
Rated Duty (MMBtu/hr)	2.10	4.03	For HAPs calculation and CO2e
Fuel Flow Rate (gal/hr)	14.56	27.90	Used ULSD HHV
Emission Factors			
Not-to-Exceed Factor	25%	25%	
NOx (g/hp-hr)	0.298	2.850	
CO (g/hp-hr)	2.610	2.600	
VOC (g/hp-hr)	0.142	0.150	
PM10 (g/hp-hr)	0.015	0.150	
PM2.5 (g/hp-hr)	0.015	0.150	
SO2	No Emission Factor	No Emission Factor	Based on Mass Balance of Sulfur
CO2 (kg CO2/MMBtu)	73.960	73.960	
CH4 (kg CH4/MMBtu)	0.003	0.003	
N2O (kg N2O/MMBtu)	0.001	0.001	
Emission Calculations (Maximum 1-hour)			
NOx (lb/hr)	0.247	4.516	
CO (lb/hr)	2.158	4.120	
VOC (lb/hr)	0.117	0.238	
PM10 (lb/hr)	0.012	0.238	
PM2.5 (lb/hr)	0.012	0.238	
SO2 (lb/hr)	0.003	0.006	
CO2 (lb/hr)	342.410	656.285	
CH4 (lb/hr)	0.014	0.027	
N2O (lb/hr)	0.003	0.005	
CO2e (lb/hr)	343.585	658.537	
Emission Calculations (Annual)			
NOx (tpy)	0.062	1.129	
CO (tpy)	0.539	1.030	
VOC (tpy)	0.029	0.059	
PM10 (tpy)	0.003	0.059	
PM2.5 (tpy)	0.003	0.059	
SO2 (tpy)	0.001	0.001	
CO2 (tonnes/yr)	77.658	148.845	
CH4 (tonnes/yr)	0.003	0.006	
N2O (tonnes/yr)	0.001	0.001	
CO2e (tonnes/yr)	77.924	149.355	
Stack Parameters			
Stack Height (ft)	10	10	From CB&I/Chiyoda Calculation
Exhaust Temperature (F)	883	908	From CB&I/Chiyoda Calculation
Exhaust Velocity (ft/s)	115	157	From CB&I/Chiyoda Calculation
Stack Diameter (ft)	0.665	0.665	From CB&I/Chiyoda Calculation
NO2/NOx Ratio	0.5	0.5	EPA's ISR Guidance (Date: 3-1-2011)

EC-6 LIQUEFACTION FACILITY FLARES

EMISSION FACTORS	Standard Factors	
	AP42 Tables 13.5-1 and 13.5-2	40 CFR Part 98 (Natural Gas)
NOx (lb/MMBtu)	0.068	
CO (lb/MMBtu)	0.310	
VOC (lb/MMBtu)	0.570	
PM10 (µg/L Exhaust)	40.000	
PM2.5 (µg/L Exhaust)	40.000	
CO2 (kg CO2/MMBtu)		53.060
CH4 (kg CH4/MMBtu)		0.001
N2O (kg N2O/MMBtu)		0.0001

MODELING PARAMETERS CALCULATION	Dry Flare Purge/Pilot/Valve Passing	Wet Flare Purge/Pilot	LP Flare Purge/Pilot/Comp Seal Gas	Dry Flare Maximum	Wet Flare Maximum	LP Flare Maximum	References/ Comments
Exhaust Flow Calculation							
Fuel Flow Rate (scfh)	6,373	2,077	18,634	55,201,793	12,905,048	992,916	From CB&I/Chiyoda Calculation (Wet/dry Purge/Pilot divided by 2)
Fuel Flow Rate (lbmol/hr)	16.84	5.49	49.23	145,847.43	34,096.14	2,623.36	
Fuel MW(lb/lbmol)	18.50	17.68	23.10	17.68	17.68	25.70	All cases not based on fuel gas from CB&I/Chiyoda Calculation
Fuel Flow Rate (lb/hr)	311.50	97.02	1,137.27	2,578,582.53	602,819.75	67,420.35	
Fuel Flow HHV (MMBtu/hr)	7.15	2.25	10.50	59,992.00	14,020.00	997.50	From CB&I/Chiyoda Calculation (Wet/dry Purge/Pilot divided by 2)
Fd Factor (dscf/MMBtu)	8,710.00	8,710.00	8,710.00	8,710.00	8,710.00	8,710.00	Method 19 for gas fuel
Exhaust O2 Concentration	3%	3%	3%	3%	3%	3%	Assumed Dry Oxygen Concentration
Exhaust Flow (dscfh) (@HHV)	72,713.90	22,882.00	106,782.65	610,105,233.97	142,580,267.04	10,144,352.09	
Exhaust Water Concentration	10%	10%	10%	10%	10%	10%	Assumed Water Content
Exhaust Flow (scfh) (@HHV)	80,793.22	25,424.44	118,647.39	677,894,704.41	158,422,518.93	11,271,502.33	
Ratio of Exhaust to Fuel	12.68	12.24	6.37	12.28	12.28	11.35	
Exhaust Flow (L/h) (@HHV)	2,288,064.12	720,020.18	3,360,094.17	19,197,978,028.81	4,486,525,736.16	319,208,945.92	
Effective Height and Diameter Calculation							
Heat Release Rate (MMBtu/hr)	6.46	2.03	9.49	54,141.81	12,664.48	898.65	Based on LHV From CB&I/Chiyoda Calculation
Buoyancy flux	7.51	2.36	11.03	62,912.79	14,716.12	1,044.23	SCREEN3 Model User's Guide
Actual Stack Height (m)	0	0	60.6552	0	0	60.6552	From CB&I/Chiyoda Calculation converted to meters
GEP stack height (m)	65.00	65.00	65.00	65.00	65.00	65.00	EPA GEP Stack Height Guideline
Effective Stack Height (m)	2.30	1.32	63.42	172.82	86.30	85.02	SCREEN3 Model User's Guide
Effective Stack Diameter (m)	0.45	0.25	0.54	40.84	19.75	5.26	SCREEN3 Model User's Guide

Note:
1.) Method 19 used to develop Exhaust Flow Rate for PM calculation. Assumed typical Boiler Exhaust parameters of 3% O2 and 10% H2O

EMISSIONS CALCULATIONS	Dry Flare Purge/Pilot/Valve Passing	Wet Flare Purge/Pilot	LP Flare Purge/Pilot/Comp Seal Gas	Dry Flare Maximum	Wet Flare Maximum	LP Flare Maximum	References/ Comments
Total Installed	3	3	1	3	3	1	From CB&I/Chiyoda Calculation (2 op, 1 spare)
Load	100%	100%	100%	100%	100%	100%	Ambient Temp does not affect emissions
Operation (hr/yr)	8,760	8,760	8,760	500	500	144	Maximum Case Intermittent
Rated Duty HHV (MMBtu/hr)	7.15	2.25	10.50	59,992.00	14,020.00	997.50	From CB&I/Chiyoda Calculation for HAPs Calculation
Emission Factors							
NOx (lb/MMBtu)	0.068	0.068	0.068	0.068	0.068	0.068	Based on HHV
CO (lb/MMBtu)	0.310	0.310	0.310	0.310	0.310	0.310	Based on HHV
VOC (lb/MMBtu)	0.570	0.570	0.570	0.570	0.570	0.570	Based on HHV
PM10 (µg/L Exhaust)	40.000	40.000	40.000	40.000	40.000	40.000	
PM2.5 (µg/L Exhaust)	40.000	40.000	40.000	40.000	40.000	40.000	
SO2	No Emission Factor	No Emission Factor	No Emission Factor	No Emission Factor	No Emission Factor	No Emission Factor	Based on Mass Balance of Sulfur
CO2 (kg CO2/MMBtu)	53.060	53.060	53.060	53.060	53.060	53.060	Based on HHV
CH4 (kg CH4/MMBtu)	0.001	0.001	0.001	0.001	0.001	0.001	Based on HHV
N2O (kg N2O/MMBtu)	0.000	0.000	0.000	0.000	0.000	0.000	Based on HHV
Additional Warm Vessel Arrival Inert Gas Emissions (Annual)							
NOx (tpy)						0.255	From CB&I/Chiyoda Calculation
CO (tpy)						0.155	From CB&I/Chiyoda Calculation
SO2 (tpy)						0.00356	From CB&I/Chiyoda Calculation
CO2 (tpy)						366.39	From CB&I/Chiyoda Calculation
Emission Calculations (Maximum 1-hour)							
NOx (lb/hr)	0.486	0.153	0.714	4,079.456	953.360	71.372	
CO (lb/hr)	2.217	0.698	3.255	18,597.520	4,346.200	311.378	
VOC (lb/hr)	4.076	1.283	5.985	34,195.440	7,991.400	568.575	
PM10 (lb/hr)	0.202	0.063	0.296	1,692.981	395.646	28.150	
PM2.5 (lb/hr)	0.202	0.063	0.296	1,692.981	395.646	28.150	
SO2 @ 16 ppm (lb/hr)	0.0173	0.0056	0.0505	149.5018	34.9505	2.7385	
CO2 (lb/hr)	836.379	263.196	1,228.249	7,017,628.751	1,640,004.586	121,772.395	
CH4 (lb/hr)	0.016	0.005	0.023	132.258	30.908	2.199	
N2O (lb/hr)	0.002	0.000	0.002	13.226	3.091	0.220	
CO2e (lb/hr)	837.243	263.468	1,229.517	7,024,876.510	1,641,698.371	121,892.905	
Emission Calculations (Annual)							
NOx (tpy)	2.130	0.670	3.127	1,019.864	238.340	5.139	
CO (tpy)	9.708	3.055	14.257	4,649.380	1,086.550	22.419	
VOC (tpy)	17.851	5.617	26.214	8,548.860	1,997.850	40.937	
PM10 (tpy)	0.884	0.278	1.298	423.245	98.911	2.027	
PM2.5 (tpy)	0.884	0.278	1.298	423.245	98.911	2.027	
SO2 @ 16 ppm (tpy)	0.076	0.025	0.221	37.375	8.738	0.197	
CO2 (tonnes/yr)	3,323.360	1,045.813	4,880.459	1,591,587.760	371,950.600	7,621.538	
CH4 (tonnes/yr)	0.063	0.020	0.092	29.996	7.010	0.144	
N2O (tonnes/yr)	0.006	0.002	0.009	3.000	0.701	0.014	
CO2e (tonnes/yr)	3,326.792	1,046.893	4,885.499	1,593,231.541	372,334.748	7,629.410	
Stack Parameters							
Stack Height (m)	2.30	1.32	63.42	172.82	86.30	85.02	
Exhaust Temperature (K)	1,273	1,273	1,273	1,273	1,273	1,273	
Exhaust Velocity (m/s)	20	20	20	20	20	20	
Stack Diameter (m)	0.45	0.25	0.54	40.84	19.75	5.26	
NO2/NOx Ratio	0.5	0.5	0.5	0.5	0.5	0.5	EPA's ISR Guidance (Date: 3-1-2011)

EC-7 LIQUEFACTION FACILITY THERMAL OXIDIZER

EMISSION FACTORS	Standard Factors	
	TCEQ Vapor Oxidizers Emission Factors	40 CFR Part 98 (Natural Gas)
NOx (lb/MMBtu)	0.1	
CO (lb/MMBtu)	0.082	
VOC (lb/MMBtu)	0.005	
PM10 (lb/MMBtu)	0.007	
PM2.5 (lb/MMBtu)	0.007	
CO2 (kg CO2/MMBtu)		53.060
CH4 (kg CH4/MMBtu)		0.001
N2O (kg N2O/MMBtu)		0.0001

Notes:

1.) Emission Factor for CO has been based on AP42 Section 1.4, to ensure CO emissions are not underestimated (TCEQ references AP42 Section 1.4 for VOC and PM emissions)

EMISSIONS CALCULATIONS	Thermal Oxidizer	References/ Comments
Total Installed	1	From CB&I/Chiyoda Calculation
Load	100%	From CB&I/Chiyoda Calculation
Operation (hr/yr)	8,760	
Rated Duty LHV (MMBtu/hr)	5.55	From CB&I/Chiyoda Calculation
Rated Duty HHV (MMBtu/hr)	6.01	From CB&I/Chiyoda Calculation
Fuel Flow Rate (lbmol/hr)	16.00	From CB&I/Chiyoda Calculation
Emission Factors		
NOx (lb/MMBtu)	0.100	Based on HHV
CO (lb/MMBtu)	0.082	Based on HHV
VOC (lb/MMBtu)	0.005	Based on HHV
PM10 (lb/MMBtu)	0.007	Based on HHV
PM2.5 (lb/MMBtu)	0.007	Based on HHV
SO2	No Emission Factor	Based on Mass Balance of Sulfur
CO2 (kg CO2/MMBtu)	53.060	Based on HHV
CH4 (kg CH4/MMBtu)	0.001	Based on HHV
N2O (kg N2O/MMBtu)	0.000	Based on HHV
Emission Calculations (Maximum 1-hour)		
NOx (lb/hr)	0.601	
CO (lb/hr)	0.495	
VOC (lb/hr)	0.032	
PM10 (lb/hr)	0.045	
PM2.5 (lb/hr)	0.045	
SO2 @ 16 ppm (lb/hr)	0.016	
CO2 (lb/hr)	703.026	
CH4 (lb/hr)	0.013	
N2O (lb/hr)	0.001	
CO2e (lb/hr)	703.752	
Emission Calculations (Annual)		
NOx (tpy)	2.632	
CO (tpy)	2.168	
VOC (tpy)	0.142	
PM10 (tpy)	0.196	
PM2.5 (tpy)	0.196	
SO2 @ 16 ppm (tpy)	0.072	
CO2 (tonnes/yr)	2793.482	
CH4 (tonnes/yr)	0.053	
N2O (tonnes/yr)	0.005	
CO2e (tonnes/yr)	2796.367	
Stack Parameters		
Stack Height (ft)	47	From CB&I/Chiyoda Calculation
Exhaust Temperature (F)	1800	From CB&I/Chiyoda Calculation
Exhaust Velocity (ft/s)	8.9	From CB&I/Chiyoda Calculation
Stack Diameter (ft)	5	From CB&I/Chiyoda Calculation
NO2/NOx Ratio	0.5	EPA's ISR Guidance (Date: 3-1-2011)

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EC-8 LIQUEFACTION FACILITY MISCELLANEOUS SOURCES

EMISSIONS CALCULATIONS	Tank	Fugitive	References/ Comments
Methane (lb/hr)		24.400	From CB&I/Chiyoda Calculation
NMHC (lb/hr)		4.100	From CB&I/Chiyoda Calculation
CO ₂ e (lb/hr)		610.000	
Emissions Calculation (Annual)			
Operation (hr/yr)	8,760	8,760	From CB&I/Chiyoda Calculation
Methane (tonnes/yr)		96.954	
CO ₂ e (tonnes/yr)		2423.841	
NMHC (tpy)	0.00	17.96	

EC-9 LIQUEFACTION FACILITY HAZARDOUS AIR POLLUTANTS (HAPS) EMISSIONS SUMMARY

Emission Unit ID	TURB1	TURB2	TURB3	TURB4	TURB5	TURB6	TRB_GEN1	TRB_GEN2	TRB_GEN3	TRB_GEN4	Aux_COMP	FPUMP	FLARE_1D	FLARE_2D	0
CT Mfg / Model	Train 1a Compression Turbine Stack	Train 1b Compression Turbine Stack	Train 2a Compression Turbine Stack	Train 2b Compression Turbine Stack	Train 3a Compression Turbine Stack	Train 3b Compression Turbine Stack	Power Generator Turbines	Power Generator Turbines	Power Generator Turbines	Power Generator Turbines	Auxiliary Air Compressor (224 kW)	Firewater Pump (429 kW)	Dry Flare Pilot/Purge	Dry Flare Pilot/Purge	Dry Flare Pilot/Purge (Not Modeled)
Source Category	CT	CT	CT	CT	CT	CT	CT	CT	CT	CT	ICE	ICE	Flare	Flare	Flare
ISO Power (kW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ISO Heat Rate (MMBtu/hr)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10°F Heat Consumption (MMBtu/hr)	1113	1113	1113	1113	1113	1113	384	384	384	384	2.1	4.025	7.15	7.15	0
Load Basis for CT EF	>80%	>80%	>80%	>80%	>80%	>80%	>80%	>80%	>80%	>80%	<600hp	<600hp	0	0	0
Fuel	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	D	D	NG	NG	NG
hrs/yr	8760	8760	8760	8760	8760	8760	8760	8760	8760	8760	500	500	8760	8760	0
1,1,2,2-Tetrachloroethane	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1,1,2-Trichloroethane	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1,3-Butadiene	0.002096224	0.002096224	0.002096224	0.002096224	0.002096224	0.002096224	0.000723226	0.000723226	0.000723226	0.000723226	2.05275E-05	3.93444E-05	0	0	0
1,3-Dichloropropene	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1,4-Dichlorobenzene	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2,2,4-Trimethylpentane	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Acetaldehyde	0.1949976	0.1949976	0.1949976	0.1949976	0.1949976	0.1949976	0.0672768	0.0672768	0.0672768	0.0672768	0.000402675	0.000771794	0.001320226	0.001320226	0
Acrolein	0.031199616	0.031199616	0.031199616	0.031199616	0.031199616	0.031199616	0.010764288	0.010764288	0.010764288	0.010764288	4.85625E-05	9.30781E-05	0.000307029	0.000307029	0
Antimony	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Arsenic	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Benzene	0.05849928	0.05849928	0.05849928	0.05849928	0.05849928	0.05849928	0.02018304	0.02018304	0.02018304	0.02018304	0.000489825	0.000938831	0.004881768	0.004881768	0
Beryllium	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biphenyl	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cadmium	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Carbon Tetrachloride	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Chlorobenzene	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Chloroform	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Chromium	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cobalt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Dibutylphthalate	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ethylbenzene	0.15599808	0.15599808	0.15599808	0.15598808	0.15599808	0.15599808	0.05382144	0.05382144	0.05382144	0.05382144	0	0	0.044335047	0.044335047	0
Ethylene Dibromide	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ethylene Dichloride	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Formaldehyde	3.4612074	3.4612074	3.4612074	3.4612074	3.4612074	3.4612074	1.1941632	1.1941632	1.1941632	1.1941632	0.0006195	0.001187375	0.035891738	0.035891738	0
HCl	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lead	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Manganese	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mercury	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Methanol	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Methylene Chloride	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
n-Hexane	0	0	0	0	0	0	0	0	0	0	0	0	0.000890385	0.000890385	0
Nickel	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PAHs	0.010724868	0.010724868	0.010724868	0.010724868	0.010724868	0.010724868	0.003700224	0.003700224	0.003700224	0.003700224	0.0000882	0.00016905	0.000429841	0.000429841	0
Phenol	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Phosphorus	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
POM (Total)	0.006337422	0.006337422	0.006337422	0.006337422	0.006337422	0.006337422	0.002186496	0.002186496	0.002186496	0.002186496	8.83376E-05	0.000169314	3.3111E-07	3.3111E-07	0
POM 2-Methylnaphthalene	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
POM 3-Methylcholanthrene	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
POM 7,12-Dimethylbenz(a)anthracene	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
POM Acenaphthene	0	0	0	0	0	0	0	0	0	0	7.455E-07	1.42888E-06	0	0	0
POM Acenaphthylene	0	0	0	0	0	0	0	0	0	0	2.6565E-06	5.09163E-06	0	0	0
POM Anthracene	0	0	0	0	0	0	0	0	0	0	9.8175E-07	1.88169E-06	0	0	0
POM Benz(a)anthracene	0	0	0	0	0	0	0	0	0	0	0.000000882	1.6905E-06	0	0	0
POM Benzo(a)pyrene	0	0	0	0	0	0	0	0	0	0	9.87E-08	1.89175E-07	0	0	0
POM Benzo(b)fluoranthene	0	0	0	0	0	0	0	0	0	0	5.20275E-08	9.97194E-08	0	0	0
POM Benzo(g,h,i)perylene	0	0	0	0	0	0	0	0	0	0	2.56725E-07	4.92056E-07	0	0	0
POM Benzo(k)fluoranthene	0	0	0	0	0	0	0	0	0	0	8.1375E-08	1.55969E-07	0	0	0
POM Chrysene	0	0	0	0	0	0	0	0	0	0	1.85325E-07	3.55206E-07	0	0	0
POM Dibenz(a,h)anthracene	0	0	0	0	0	0	0	0	0	0	3.06075E-07	5.86644E-07	0	0	0
POM Fluoranthene	0	0	0	0	0	0	0	0	0	0	3.99525E-06	7.65756E-06	0	0	0
POM Fluorene	0	0	0	0	0	0	0	0	0	0	0.000015435	2.95838E-05	0	0	0
POM Indeno(1,2,3-c,d)pyrene	0	0	0	0	0	0	0	0	0	0	1.96875E-07	3.77344E-07	0	0	0
POM Naphthalene	0.006337422	0.006337422	0.006337422	0.006337422	0.006337422	0.006337422	0.002186496	0.002186496	0.002186496	0.002186496	0.00004452	0.00008533	0.000337732	0.000337732	0
POM Phenanthrene	0	0	0	0	0	0	0	0	0	0	0.000015435	2.95838E-05	0	0	0
POM Pyrene	0	0	0	0	0	0	0	0	0	0	2.5095E-06	4.80988E-06	0	0	0
Propionaldehyde	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Propylene Oxide	0.14137326	0.14137326	0.14137326	0.14137326	0.14137326	0.14137326	0.04877568	0.04877568	0.04877568	0.04877568	0	0	0	0	0
Selenium	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Styrene	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tetrachloroethylene	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Toluene	0.6337422	0.6337422	0.6337422	0.6337422	0.6337422	0.6337422	0.2186496	0.2186496	0.2186496	0.2186496	0.000214725	0.000411556	0.001780771	0.001780771	0
Trichloroethylene	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Vinyl Chloride	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Vinylidene Chloride	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Xylenes(m,p,o)	0.31199616	0.31199616	0.31199616	0.31199616	0.31199616	0.31199616	0.10764288	0.10764288	0.10764288	0.10764288	0.000149625	0.000286781	0.000890385	0.000890385	0
CDD/CDF	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SOURCE TOTAL (tpy)	5.008	5.008	5.008	5.008	5.008	5.008	1.728	1.728	1.728	1.728	0.002	0.004	0.091	0.091	0.000

Emission Unit ID	FLARE_1W	FLARE_2W	0	DRY_MAX1	DRY_MAX2	0	WET_MAX1	WET_MAX2	0	LP_FLARE	LP_MAX	TH_OX	Total
CT Mfg / Model	Wet Flare Pilot/Purge	Wet Flare Pilot/Purge	Wet Flare Pilot/Purge (Not Modeled)	Dry Flare Maximum Case	Dry Flare Maximum Case	Dry Flare Maximum Case (Not Modeled)	Wet Flare Maximum Case	Wet Flare Maximum Case	Wet Flare Maximum Case (Not Modeled)	LP Flare Pilot/Purge	LP Flare Maximum Flow	Thermal Oxidizer	
Source Category	Flare	Flare	Flare	Flare	Flare	Flare	Flare	Flare	Flare	Flare	Flare	Heater	
ISO Power (kW)	0	0	0	0	0	0	0	0	0	0	0	0	
ISO Heat Rate (MMBtu/hr)	0	0	0	0	0	0	0	0	0	0	0	0	
10°F Heat Consumption (MMBtu/hr)	2.25	2.25	0	59992	59992	0	14020	14020.00	0.00	10.50	997.50	6.01	
Load Basis for CT EF	0	0	0	0	0	0	0	0	0	0	0.00	0.00	
Fuel	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	
hrs/yr	8760	8760	0	500	500	0	500	500	0	8760	144.00	8760.00	
1,1,2,2-Tetrachloroethane	0	0	0	0	0	0	0	0	0	0	0	0	0.00
1,1,2-Trichloroethane	0	0	0	0	0	0	0	0	0	0	0	0	0.00
1,3-Butadiene	0	0	0	0	0	0	0	0	0	0	0	0	0.02
1,3-Dichloropropene	0	0	0	0	0	0	0	0	0	0	0	0	0.00
1,4-Dichlorobenzene	0	0	0	0	0	0	0	0	0	0	0	0	0.00
2,2,4-Trimethylpentane	0	0	0	0	0	0	0	0	0	0	0	0	0.00
Acetaldehyde	0.000415456	0.000415456	0	0.632268627	0.632268627	0	0.147759804	0.147759804	0	0.001938794	0.003027706	0	3.01
Acrolein	9.66176E-05	9.66176E-05	0	0.147039216	0.147039216	0	0.034362745	0.034362745	0	0.000450882	0.000704118	0	0.60
Antimony	0	0	0	0	0	0	0	0	0	0	0	0	0.00
Arsenic	0	0	0	0	0	0	0	0	0	0	0	0	0.00
Benzene	0.001536221	0.001536221	0	2.337923529	2.337923529	0	0.546367647	0.546367647	0	0.007169029	0.011195471	5.41954E-05	6.23
Beryllium	0	0	0	0	0	0	0	0	0	0	0	0	0.00
Biphenyl	0	0	0	0	0	0	0	0	0	0	0	0	0.00
Cadmium	0	0	0	0	0	0	0	0	0	0	0	0	0.00
Carbon Tetrachloride	0	0	0	0	0	0	0	0	0	0	0	0	0.00
Chlorobenzene	0	0	0	0	0	0	0	0	0	0	0	0	0.00
Chloroform	0	0	0	0	0	0	0	0	0	0	0	0	0.00
Chromium	0	0	0	0	0	0	0	0	0	0	0	0	0.00
Cobalt	0	0	0	0	0	0	0	0	0	0	0	0	0.00
Dibutylphthalate	0	0	0	0	0	0	0	0	0	0	0	0	0.00
Ethylbenzene	0.013951588	0.013951588	0	21.23246275	21.23246275	0	4.961980392	4.961980392	0	0.065107412	0.101674588	0	53.82
Ethylene Dibromide	0	0	0	0	0	0	0	0	0	0	0	0	0.00
Ethylene Dichloride	0	0	0	0	0	0	0	0	0	0	0	0	0.00
Formaldehyde	0.011294603	0.011294603	0	17.18888431	17.18888431	0	4.017004902	4.017004902	0	0.052708147	0.082311353	0.001935573	68.19
HCl	0	0	0	0	0	0	0	0	0	0	0	0	0.00
Lead	0	0	0	0	0	0	0	0	0	0	0	1.29039E-05	0.00
Manganese	0	0	0	0	0	0	0	0	0	0	0	0	0.00
Mercury	0	0	0	0	0	0	0	0	0	0	0	0	0.00
Methanol	0	0	0	0	0	0	0	0	0	0	0	0	0.00
Methylene Chloride	0	0	0	0	0	0	0	0	0	0	0	0	0.00
n-Hexane	0.000280191	0.000280191	0	0.426413725	0.426413725	0	0.099651961	0.099651961	0	0.001307559	0.002041941	0.046453765	1.10
Nickel	0	0	0	0	0	0	0	0	0	0	0	0	0.00
PAHs	0.000135265	0.000135265	0	0.205854902	0.205854902	0	0.048107843	0.048107843	0	0.000631235	0.000985765	0	0.59
Phenol	0	0	0	0	0	0	0	0	0	0	0	0	0.00
Phosphorus	0	0	0	0	0	0	0	0	0	0	0	0	0.00
POM (Total)	1.04196E-07	1.04196E-07	0	0.000158572	0.000158572	0	3.70579E-05	3.70579E-05	0	4.86246E-07	7.59343E-07	1.80265E-05	0.05
POM 2-Methylnaphthalene	0	0	0	0	0	0	0	0	0	0	0	6.18609E-07	0.00
POM 3-Methylcholanthrene	0	0	0	0	0	0	0	0	0	0	0	4.73828E-08	0.00
POM 7,12-Dimethylbenz(a)anthracene	0	0	0	0	0	0	0	0	0	0	0	4.13284E-07	0.00
POM Acenaphthene	0	0	0	0	0	0	0	0	0	0	0	4.73828E-08	0.00
POM Acenaphthylene	0	0	0	0	0	0	0	0	0	0	0	4.73828E-08	0.00
POM Anthracene	0	0	0	0	0	0	0	0	0	0	0	6.31771E-08	0.00
POM Benz(a)anthracene	0	0	0	0	0	0	0	0	0	0	0	4.73828E-08	0.00
POM Benzo(a)pyrene	0	0	0	0	0	0	0	0	0	0	0	3.15886E-08	0.00
POM Benzo(b)fluoranthene	0	0	0	0	0	0	0	0	0	0	0	4.73828E-08	0.00
POM Benzo(g,h,i)perylene	0	0	0	0	0	0	0	0	0	0	0	3.15886E-08	0.00
POM Benzo(k)fluoranthene	0	0	0	0	0	0	0	0	0	0	0	4.73828E-08	0.00
POM Chrysene	0	0	0	0	0	0	0	0	0	0	0	4.73828E-08	0.00
POM Dibenz(a,h)anthracene	0	0	0	0	0	0	0	0	0	0	0	3.15886E-08	0.00
POM Fluoranthene	0	0	0	0	0	0	0	0	0	0	0	7.6339E-08	0.00
POM Fluorene	0	0	0	0	0	0	0	0	0	0	0	7.10743E-08	0.00
POM Indeno(1,2,3-c,d)pyrene	0	0	0	0	0	0	0	0	0	0	0	4.73828E-08	0.00
POM Naphthalene	0.000106279	0.000106279	0	0.161743137	0.161743137	0	0.03779902	0.03779902	0	0.000495971	0.000774529	1.57416E-05	0.45
POM Phenanthrene	0	0	0	0	0	0	0	0	0	0	0	4.39607E-07	0.00
POM Pyrene	0	0	0	0	0	0	0	0	0	0	0	1.28987E-07	0.00
Propional[dehyde]	0	0	0	0	0	0	0	0	0	0	0	0	0.00
Propylene Oxide	0	0	0	0	0	0	0	0	0	0	0	0	1.04
Selenium	0	0	0	0	0	0	0	0	0	0	0	0	0.00
Styrene	0	0	0	0	0	0	0	0	0	0	0	0	0.00
Tetrachloroethylene	0	0	0	0	0	0	0	0	0	0	0	0	0.00
Toluene	0.000560382	0.000560382	0	0.852827451	0.852827451	0	0.199303922	0.199303922	0	0.002615118	0.004083882	8.77451E-05	6.79
Trichloroethylene	0	0	0	0	0	0	0	0	0	0	0	0	0.00
Vinyl Chloride	0	0	0	0	0	0	0	0	0	0	0	0	0.00
Vinylidene Chloride	0	0	0	0	0	0	0	0	0	0	0	0	0.00
Xylenes(m,p,o)	0.000280191	0.000280191	0	0.426413725	0.426413725	0	0.099651961	0.099651961	0	0.001307559	0.002041941	0	3.36
CDD/CDF	0	0	0	0	0	0	0	0	0	0	0	0	0.00
SOURCE TOTAL (tpy)	0.029	0.029	0.000	43.450	43.450	0.000	10.154	10.154	0.000	0.133	0.208	0.049	144.80

[illegible]

EC-11 LIQUEFACTION FACILITY ANNUAL FUEL CONSUMPTION

Gas-Fired Equipment (Fuel Gas Users)	Rated Duty (HHV)	Daily Average Fuel Flow
	MMBtu/hr	MMSCFD
Train 1a Compression Turbine	1113.00	24.57
Train 1b Compression Turbine	1113.00	24.57
Train 2a Compression Turbine	1113.00	24.57
Train 2b Compression Turbine	1113.00	24.57
Train 3a Compression Turbine	1113.00	24.57
Train 3b Compression Turbine	1113.00	24.57
Power Generator Turbines	384.00	8.48
Power Generator Turbines	384.00	8.48
Power Generator Turbines	384.00	8.48
Power Generator Turbines	384.00	8.48
Dry Flare Pilot/Purge	7.15	0.16
Dry Flare Pilot/Purge	7.15	0.16
Dry Flare Pilot/Purge (Not Modeled)	0.00	0.00
Wet Flare Pilot/Purge	2.25	0.05
Wet Flare Pilot/Purge	2.25	0.05
Wet Flare Pilot/Purge (Not Modeled)	0.00	0.00
LP Flare Pilot/Purge	10.50	0.23
Thermal Oxidizer	6.01	0.13
Total Fuel Gas Consumption	8,249	182
Liquid-Driven Equipment (Diesel Users)	Rated Duty (HHV)	Daily Average Diesel Flow
	MMBtu/hr	gal/day
Auxiliary Air Compressor (224 kW)	2.10	349.40
Firewater Pump (429 kW)	4.03	669.68
Mobile Equipment Emissions (Normal Operation)	6.53	1086.64
Non-Road/Portable Equipment Emissions (Normal Operation)	27.32	4546.20
Marine Terminal Emissions (Normal Operation)	6,120	1018295.68
Total Diesel Consumption	6,160.2	1,024,947.6
Additional GHG Emission Sources not from Fuel Gas or Diesel Consumption		
Dry Flare Maximum Case		
Wet Flare Maximum Case		
LP Flare Maximum Flow (Maintenance)		
Tank Emissions		
Fugitive Emissions		

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EC-12 LIQUEFACTION FACILITY MOBILE SOURCE EMISSIONS SUMMARY

Moves Vehicle Class	Total Miles Per Year	MOVES											Ton/year										
		EFs (g/mi) ¹																					
		VOC	NOx	CO	SO ₂	PM ₁₀	PM _{2.5}	CO ₂	CH ₄	N ₂ O	CO ₂ e ⁴	HAPs ²	VOC	NOx	CO	SO ₂	PM ₁₀	PM _{2.5}	CO ₂	CH ₄	N ₂ O	CO ₂ e ⁴	HAPs ²
Single Unit Short-Haul Truck	306,480	0.384	3.257	1.296	0.014	0.217	0.188	1624.180	0.102	0.004	1627.959	0.070	0.1298	1.1004	0.4379	0.0046	0.0733	0.0637	548.7099	0.0344	0.0014	549.9866	0.0238
Light Commercial Truck	191,040	0.079	0.796	1.642	0.006	0.041	0.041	729.512	0.042	0.003	731.571	0.020	0.0166	0.1676	0.3458	0.0013	0.0085	0.0087	153.6255	0.0088	0.0007	154.0591	0.0042
Intercity Bus	100,800	0.594	5.731	1.842	0.020	0.440	0.269	2310.040	0.098	0.003	2313.465	0.076	0.0661	0.6368	0.2046	0.0022	0.0489	0.0299	256.6768	0.0108	0.0004	257.0573	0.0085
Passenger Truck	1,384,800	0.079	0.887	1.487	0.007	0.041	0.044	786.544	0.048	0.004	788.971	0.022	0.1206	1.3542	2.2700	0.0101	0.0625	0.0667	1200.6505	0.0733	0.0063	1204.3560	0.0333
TOTAL PER POLLUTANT (tpy)													0.33	3.26	3.26	0.02	0.19	0.17	2159.66	0.13	0.01	2165.46	0.07

Note 1: Emissions estimates are based on EPA's MOVES2014 motor vehicle emissions estimation program. Year 2027 is used as the base year for North Slope Borough, based on latest county-specific MOVES2014 input data available from Alaska DEC.

Note 2: HAPs are aggregated for benzene, 1,3-butadiene, formaldehyde, acetaldehyde, acrolein, toluene, and xylene

Note 3: tons/year emissions = (Average distance traveled (mi/year)) * Emission factor (g/mi) / (453.59 g/lb) * (1 / 2000)

Note 4: Greenhouse gasses (GHG) are converted to carbon dioxide equivalents (CO₂e) using 100-year Global Warming Potentials values from IPCC's Fourth Assessment Report (AR4) Chapter 2, Table 2.14 of Climate Change 2007: The Physical Science Basis. Contribution of Working Group I to the Fourth Assessment Report of the IPCC

CO₂ = 1, CH₄ = 25, N₂O = 298

EC-13 LIQUEFACTION FACILITY NON-ROAD/PORTABLE EMISSIONS SUMMARY

Engine Description	Equipment category based on NONROAD classification	SCC ¹	Fuel Type	Equipment Horsepower	Operating hrs/year	BSFC ²	Emission Factors (g/hp-hr) ²				Age Factor ³	NOx "A" ³	CO "A" ³	PM "A" ³	THC "A" ³	Deterioration Factors ²				Adjusted Emission Factors (g/hp-hr) ²				Load Factor ²	Emissions (ton/year)			
							NOx	CO	PM	THC						NOx	CO	PM	THC	NOx	CO	PM ⁵	THC		NOx	CO	PM	VOC ⁶
Air Compressor -900CFM (Sullair; caterpillar C-9 ATAAC engine)	Light Commercial Air Compressor	2270006015	Diesel	300	2880	0.367	0.276	0.084	0.0092	0.1314	1	0.008	0.151	0.473	0.027	1.008	1.151	1.473	1.027	0.278	0.097	0.014	0.135	0.43	0.35	0.12	0.02	0.18
Motor Grader - Cat 16G (6 tires, 7gph, 6-cylinder engine)	Graders	2270002048	Diesel	250	3600	0.371	0.28	0.11	0.0092	0.13	1	0.008	0.151	0.473	0.027	1.008	1.151	1.473	1.027	0.282	0.127	0.014	0.134	0.59	0.40	0.18	0.02	0.20
Backhoe (CAT 966F)	Tractors/Loaders/Backhoes	2270002066	Diesel	220	720	0.433	0.28	0.19	0.0092	0.13	1	0.008	0.151	0.473	0.027	1.008	1.151	1.473	1.027	0.282	0.219	0.014	0.134	0.21	0.13	0.10	0.01	0.06
Crane (small) - 50/60 ton , Grove, RT700E (Cummins QSB engine)	Crane	2270002045	Diesel	240	2880	0.367	0.28	0.07	0.0092	0.13	1	0.008	0.151	0.473	0.027	1.008	1.151	1.473	1.027	0.282	0.081	0.014	0.134	0.43	0.28	0.08	0.01	0.14
Crane (large) - 200 ton, Manitowoc 888 (Cummins M11 engine)	Crane	2270002045	Diesel	330	720	0.367	0.28	0.08	0.0092	0.13	1	0.008	0.151	0.473	0.027	1.008	1.151	1.473	1.027	0.282	0.092	0.014	0.134	0.43	0.39	0.13	0.02	0.19
Crane (large) - 90 ton, Grove 890E (Cummins QSB engine)	Crane	2270002045	Diesel	275	720	0.367	0.28	0.07	0.0092	0.13	1	0.008	0.151	0.473	0.027	1.008	1.151	1.473	1.027	0.282	0.081	0.014	0.134	0.43	0.32	0.09	0.02	0.16
Dozer - Cat D9, 475 HP	Rubber Tire Dozer	2270002063	Diesel	475	1500	0.371	0.28	0.13	0.0092	0.13	1	0.008	0.151	0.473	0.027	1.008	1.151	1.473	1.027	0.282	0.150	0.014	0.134	0.59	0.76	0.40	0.04	0.38
Boom Truck (National Crane 800D)	Crane	2270002045	Diesel	350	720	0.367	0.28	0.08	0.0092	0.13	1	0.008	0.151	0.473	0.027	1.008	1.151	1.473	1.027	0.282	0.092	0.014	0.134	0.43	0.41	0.13	0.02	0.20
Loader - Cat 988H, 501HP	Rubber Tire Loader	2270002060	Diesel	501	7200	0.371	0.28	0.13	0.0092	0.13	1	0.008	0.151	0.473	0.027	1.008	1.151	1.473	1.027	0.282	0.150	0.014	0.134	0.59	0.81	0.43	0.04	0.40
Light Plants (Genie TML-4000)	Light Commercial Generator Set	2270006005	Diesel	15	36000	0.408	0.28	0.22	0.0092	0.13	1	0.008	0.151	0.473	0.027	1.008	1.151	1.473	1.027	0.282	0.253	0.014	0.134	0.43	0.02	0.02	0.00	0.01
Forklift - 15 Ton (Cat P30000)	Forklifts	2270003020	Diesel	148	1440	0.371	0.28	0.13	0.0092	0.13	1	0.008	0.151	0.473	0.027	1.008	1.151	1.473	1.027	0.282	0.150	0.014	0.134	0.59	0.24	0.13	0.01	0.12
Forklift - Cat (2P5000)	Forklifts	2270003020	Diesel	61	4320	0.412	0.28	0.36	0.0092	0.13	1	0.008	0.151	0.473	0.027	1.008	1.151	1.473	1.027	0.282	0.414	0.014	0.134	0.59	0.10	0.14	0.00	0.05
Generator - 100 kW	Light Commercial Generator Set	2270006005	Diesel	135	2880	0.367	0.28	0.09	0.0092	0.13	1	0.008	0.151	0.473	0.027	1.008	1.151	1.473	1.027	0.282	0.104	0.014	0.134	0.43	0.16	0.06	0.01	0.08
Generator - 50 kW	Light Commercial Generator Set	2270006005	Diesel	67	14400	0.408	0.28	0.24	0.0092	0.13	1	0.008	0.151	0.473	0.027	1.008	1.151	1.473	1.027	0.282	0.276	0.014	0.134	0.43	0.08	0.08	0.00	0.04
Man lifts - 80' Genie (Z80/60)	Aerial Lift	2270003010	Diesel	78	1440	0.481	0.28	0.61	0.0092	0.13	1	0.008	0.151	0.473	0.027	1.008	1.151	1.473	1.027	0.282	0.702	0.014	0.134	0.21	0.04	0.11	0.00	0.02
Man lift - 45' Genie (Z45, Perkins 404D-22 4 cylinder engine)	Aerial Lift	2270003010	Diesel	51	2880	0.481	0.28	0.61	0.0092	0.13	1	0.008	0.151	0.473	0.027	1.008	1.151	1.473	1.027	0.282	0.702	0.014	0.134	0.21	0.03	0.07	0.00	0.01
Zoom Boom - Telehandler (used on warehouse), GTH-1056	Forklifts	2270003020	Diesel	125	7200	0.371	0.28	0.13	0.0092	0.13	1	0.008	0.151	0.473	0.027	1.008	1.151	1.473	1.027	0.282	0.150	0.014	0.134	0.59	0.20	0.11	0.01	0.10
Bobcat (2500 lb capacity, 75 hp, Kubota S250)	Skid Steer Loader	2270002072	Diesel	75	8640	0.481	0.28	0.61	0.0092	0.13	1	0.008	0.151	0.473	0.027	1.008	1.151	1.473	1.027	0.282	0.702	0.014	0.134	0.21	0.04	0.11	0.00	0.02
Welding Machines (in shop) (Lincoln Electric)	Light Commercial Welders	2270006025	Diesel	36	8640	0.481	0.28	0.39	0.0092	0.13	1	0.008	0.151	0.473	0.027	1.008	1.151	1.473	1.027	0.282	0.449	0.014	0.134	0.21	0.02	0.03	0.00	0.01

Heater Description	Fuel Type	Equipment MMBtu/hr	Operating hrs/year	Emission Factors (lb/MMBtu)				Emissions (ton/year)			
				NOx	CO	PM	THC	NOx	CO	PM	THC
Ground thaw Heater (E3000)	Diesel	0.60	8640	0.14	0.04	0.02	0.00	0.38	0.09	0.06	0.01
Tioga Heaters (600,000 Btu/hr heater)	Diesel	0.60	56160	0.14	0.04	0.02	0.00	2.44	0.61	0.40	0.04

Total Non-Road/Portable Emissions	Emissions (ton/year)			
	NOx	CO	PM	THC
	7.59	3.22	0.69	2.43

NOTES:

- Note 1: SCC code based on Appendix A of "Median Life, Annual Activity, and Load Factor Values for Nonroad Engine Emissions Modeling", July 2010, EPA-420-R-10-018.
- Note 2: Brake-specific fuel consumption, zero hour steady state emission factor (EFss; g/hp-hr), and load factor are from NMM/NONROAD08 model factors dated April 5, 2009. EFss from NMM/NONROAD08 have transient adjustment factors (TAFs) built in. The EFss are weighted averages based on Tier 4 engines.
- Note 3: Age factor and Deterioration factors calculated using Equation 4 from "Exhaust and Crankcase Emission Factors for Nonroad Engine Modeling - Compression-Ignition", July 2010, EPA-420-R-10-018. Age Factor = LF * cumulative hours / median life (where Age factor is capped at 1. For this calculation, age factor is assumed to be 1 for simplification purposes). Deterioration Factor = 1 + (A * Age Factor^b), where b = 1 for diesel engines and A is taken from Table A6 from above mentioned source
- Note 4: Adjusted Emission Factors are calculated using Equation 1 from, "Exhaust and Crankcase Emission Factors for Nonroad Engine Modeling - Compression-Ignition", July 2010, EPA-420-R-10-018. Adjusted EF = EFss * TAF * DF (as stated in Note 2, EFss have TAFs built in)
- Note 5: Adjusted Emission Factors for PM₁₀ are calculated using Equation 2 from, "Exhaust and Crankcase Emission Factors for Nonroad Engine Modeling - Compression-Ignition", July 2010, EPA-420-R-10-018. The correction factor S_{PM10} is made to account for fuel sulfur variations; inputs specific to this calculation are noted below
- 0.02247 soxcnv (fraction of fuel sulfur converted to direct PM) for Base, T0, T1, T2, T3, T3B, T4A, T4B
- 0.30 soxcnv (fraction of fuel sulfur converted to direct PM) for Base, T4 and T4N
- 0.03 soxcnv (fraction of fuel sulfur converted to direct PM) for gasoline engines
- 0.0015 soxdsl (weight percent of sulfur in diesel fuel)
- 0.0015 soxbas (default certification fuel sulfur weight percent, 0.0015 is default for Tier 4 engines)
- Note 6: Adjusted emissions from THC to VOC by 1.053 is the ratio of VOC to THC (for diesel equipment) from "Conversion Factors for Hydrocarbon Components", July 2010, EPA-420-R-10-015.

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EC-14 LIQUEFACTION FACILITY OFFSITE SOURCE EMISSIONS SUMMARY

Tesoro Refinery Emissions – Actual Emissions

Model ID	Point Sources Description	Location			Emissions (g/sec)														
		UTM X	UTM Y	Base Elev. (m)	NOx (1-hr)	NOx (ann)	PM _{2.5} /PM ₁₀ (24-hr)	PM _{2.5} /PM ₁₀ (annual)	SO2 (1-hr)	SO2 (3-hr & 24-hr)	SO2 annual	CO	Equip Type	Fuel Type	PMF/SOIL	EC - PM2.5	EC - PM10	SOA - PM2.5	SOA - PM10
TR1	Crude Heater H-101A, Unit 0001	589027.60	6728817.60	40	2.684E+00	2.684E+00	7.278E-02	7.278E-02	2.647E-02	2.647E-02	2.647E-02	8.052E-01	Heater	Gas	0.000E+00	1.819E-02	1.819E-02	5.458E-02	5.458E-02
TR2	Crude Heater H-101B, Unit 0002	589028.02	6728824.94	40	7.646E-01	7.646E-01	9.493E-02	9.493E-02	3.423E-02	3.423E-02	3.423E-02	1.049E+00	Heater	Gas	0.000E+00	2.373E-02	2.373E-02	7.120E-02	7.120E-02
TR3_5	Pow erformer Preheater H-201, Unit 0003 - 0005	589117.10	6728825.10	40	8.440E-01	8.440E-01	6.415E-02	6.415E-02	2.330E-02	2.330E-02	2.330E-02	7.088E-01	Heater	Gas	0.000E+00	0.000E+00	1.604E-02	0.000E+00	4.811E-02
TR6	Pow erformer Reheater H-204, Unit 0006	589116.70	6728835.80	40	2.836E-01	2.836E-01	2.647E-02	2.647E-02	9.493E-03	9.493E-03	9.493E-03	2.923E-01	Heater	Gas	0.000E+00	6.616E-03	6.616E-03	1.985E-02	1.985E-02
TR7	Pow erformer Reheater H-205, Unit 0007	589112.70	6728843.50	40	1.815E-01	1.815E-01	1.697E-02	1.697E-02	6.041E-03	6.041E-03	6.041E-03	1.870E-01	Heater	Gas	0.000E+00	4.243E-03	4.243E-03	1.273E-02	1.273E-02
TR8	Hydrocracker Recycle Gas Heater, H-401, Unit 0008	589188.20	6728839.60	40	1.588E-01	1.588E-01	1.467E-02	1.467E-02	5.466E-03	5.466E-03	5.466E-03	1.634E-01	Heater	Gas	0.000E+00	3.668E-03	3.668E-03	1.100E-02	1.100E-02
TR9	Hydrocracker Recycle Gas Heater, H-402, Unit 0009	589170.80	6728839.20	40	9.464E-02	9.464E-02	8.918E-03	8.918E-03	3.164E-03	3.164E-03	3.164E-03	9.723E-02	Heater	Gas	0.000E+00	2.229E-03	2.229E-03	6.688E-03	6.688E-03
TR10	Hydrocracker Fractionater Reboiler, H-403, Unit 0010	589165.50	6728839.00	40	2.592E-01	2.592E-01	3.222E-02	3.222E-02	1.151E-02	1.151E-02	1.151E-02	3.558E-01	Heater	Gas	0.000E+00	8.055E-03	8.055E-03	2.416E-02	2.416E-02
TR11	Hydrocracker Fractionater Reboiler, H-404, Unit 0011	589160.20	6728838.90	40	3.484E-01	3.484E-01	3.251E-02	3.251E-02	1.179E-02	1.179E-02	1.179E-02	3.587E-01	Heater	Gas	0.000E+00	8.127E-03	8.127E-03	2.438E-02	2.438E-02
TR12	Hot Oil Heater, H-609, Unit 0012	588857.42	6728656.97	40	2.160E-01	2.160E-01	1.640E-02	1.640E-02	6.041E-03	6.041E-03	6.041E-03	1.815E-01	Heater	Gas	0.000E+00	4.099E-03	4.099E-03	1.230E-02	1.230E-02
TR15	Fired Steam Generator, H-701, Unit 0015	589041.80	6728857.40	40	1.726E-03	1.726E-03	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	1.438E-03	Generator	Gas	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00
TR16	Fired Steam Generator, H-702, Unit 0016	589035.80	6728856.10	40	6.214E-02	6.214E-02	4.603E-03	4.603E-03	1.726E-03	1.726E-03	1.726E-03	5.236E-02	Generator	Gas	0.000E+00	2.253E-03	2.253E-03	2.350E-03	2.350E-03
TR17	Natural Gas Supply Heater, H-704, Unit 0017	589149.60	6728575.30	40	3.452E-02	3.452E-02	2.589E-03	2.589E-03	8.630E-04	8.630E-04	8.630E-04	2.905E-02	Heater	Gas	0.000E+00	6.472E-04	6.472E-04	1.942E-03	1.942E-03
TR18	Fired Steam Generator, H-801, Unit 0018	589029.70	6728856.00	40	5.840E-02	5.840E-02	4.315E-03	4.315E-03	2.877E-04	2.877E-04	2.877E-04	4.890E-02	Generator	Gas	0.000E+00	2.112E-03	2.112E-03	2.203E-03	2.203E-03
TR19	Hot Glycol Heater, H-802, Unit 0019	589148.10	6728833.30	40	6.674E-02	6.674E-02	5.178E-03	5.178E-03	2.877E-04	2.877E-04	2.877E-04	5.609E-02	Heater	Gas	0.000E+00	1.294E-03	1.294E-03	3.883E-03	3.883E-03
TR20	Hydrogen Reformer Furnace, H-1001, Unit 0020	589233.00	6728817.70	40	4.421E-01	4.421E-01	4.114E-02	4.114E-02	2.963E-02	2.963E-02	2.963E-02	4.554E-01	Heater	Gas	0.000E+00	1.028E-02	1.028E-02	3.085E-02	3.085E-02
TR21_26	Heaters, H-1101-1106, Units 0021-0026 (common stack)	589216.51	6728869.90	40	4.056E-02	4.056E-02	3.164E-03	3.164E-03	0.000E+00	0.000E+00	0.000E+00	3.452E-02	Heater	Gas	0.000E+00	0.000E+00	7.911E-04	2.373E-03	2.373E-03
TR27	Prip Absorber Feed Furnace, H-1201/1203, Unit 0027	589123.70	6728843.50	40	7.019E-02	7.019E-02	5.178E-03	5.178E-03	2.877E-04	2.877E-04	2.877E-04	5.782E-02	Heater	Gas	0.000E+00	1.294E-03	1.294E-03	3.883E-03	3.883E-03
TR28	Prip Recycle H2 Furnace, H-1202, Unit 0028	589128.50	6728843.80	40	1.271E-01	1.271E-01	9.493E-03	9.493E-03	2.877E-04	2.877E-04	2.877E-04	1.047E-01	Heater	Gas	0.000E+00	2.373E-03	2.373E-03	7.120E-03	7.120E-03
TR29	Vacuum Tow er Heater, H-1701, Unit 0029	588965.36	6728845.83	40	4.157E-01	4.157E-01	5.149E-02	5.149E-02	1.870E-02	1.870E-02	1.870E-02	5.704E-01	Heater	Gas	0.000E+00	1.287E-02	1.287E-02	3.862E-02	3.862E-02
TR32	Solar Centaur Turbine, GT-1400	589304.50	6728918.50	40	1.179E-01	1.179E-01	6.904E-03	6.904E-03	2.877E-04	2.877E-04	2.877E-04	7.508E-02	Turbine	Gas	0.000E+00	1.988E-03	1.988E-03	4.916E-03	4.916E-03
TR33	Solar Centaur Turbine, GT-1410	589304.50	6728918.50	40	6.588E-02	6.588E-02	3.740E-03	3.740E-03	0.000E+00	0.000E+00	0.000E+00	4.200E-02	Turbine	Gas	0.000E+00	1.077E-03	1.077E-03	2.663E-03	2.663E-03
TR34	Electrical Generator CAT 3412, EG-704 Unit 0034	589054.42	6728869.43	40	2.877E-03	2.877E-03	2.877E-04	2.877E-04	0.000E+00	0.000E+00	0.000E+00	5.753E-04	Generator	Diesel	0.000E+00	2.478E-04	2.490E-04	3.984E-05	3.866E-05
TR35	Stew art-Stevens Generator, EG-801, Unit 0035	589181.30	6728736.30	40	1.151E-03	1.151E-03	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	2.877E-04	Generator	Diesel	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00
TR36	North Caterpillar CAT G399, P-605A, Unit 0036	588891.80	6728653.60	37	4.108E-01	4.108E-01	7.040E-03	1.005E-03	1.171E-02	1.171E-02	1.671E-03	2.237E-01	Generator	Diesel	0.000E+00	6.065E-03	6.094E-03	9.749E-04	9.460E-04
TR37	South Caterpillar CAT G399, P-605B, Unit 0037	588891.90	6728643.70	37	2.100E-02	2.100E-02	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	1.726E-03	Generator	Diesel	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00
TR38	North Cummins NHS6-1F, P-708A, Unit 0038	588655.80	6728681.90	30	1.102E-01	1.102E-01	7.767E-03	7.767E-03	0.000E+00	0.000E+00	0.000E+00	2.359E-02	Generator	Diesel	0.000E+00	6.691E-03	6.723E-03	1.076E-03	1.044E-03
TR40	Upper Tank Farm CAT 3412DT, P-708C, Unit 0040	589336.30	6728894.30	40	1.187E-01	1.187E-01	3.104E-02	2.126E-03	1.346E-02	1.965E-01	1.346E-02	4.605E-01	Tank	N/A	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00
TR41	Cooling Tow er CAT G333. P-719C, Unit 0041	589058.60	6728708.60	40	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	Cooling Tow er	N/A	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00
TR42	Refinery Flare, J-801, Unit 0042	589399.00	6728816.00	40	3.706E-02	3.706E-02	2.816E-03	2.816E-03	1.016E-02	1.016E-02	1.016E-02	3.113E-02	Flare	Gas	0.000E+00	7.041E-04	7.041E-04	2.112E-03	2.112E-03
TR43	SRU Flare, Unit 0043	589238.60	6728872.13	40	1.726E-03	1.726E-03	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	1.438E-03	Flare	Gas	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00
TR44	Soil Vapor Extraction Unit, E77 SVE/TO, Unit 0044	589292.80	6728693.30	40	6.176E-03	6.176E-03	4.694E-04	4.694E-04	1.046E-03	1.046E-03	1.046E-03	5.188E-03	Heater	Gas	0.000E+00	1.174E-04	1.174E-04	3.521E-04	3.521E-04
TR45	Soil Vapor Extraction Unit, LTF SVE, Unit 0045	588747.60	6728858.63	40	2.471E-02	2.471E-02	1.878E-03	1.878E-03	4.183E-03	4.183E-03	4.183E-03	2.075E-02	Heater	Gas	0.000E+00	4.694E-04	4.694E-04	1.408E-03	1.408E-03
TR118	DDU Fractionator Reboiler, H1602 Unit 118	589282.00	6728838.00	40	6.329E-02	6.329E-02	1.726E-03	1.726E-03	4.315E-03	4.315E-03	4.315E-03	9.493E-03	Heater	Gas	0.000E+00	4.315E-04	4.315E-04	1.294E-03	1.294E-03
TR119	H-1801-Naptha Splitter Reboiler Heater	589019.00	6728839.70	40	5.233E-01	5.233E-01	6.501E-02	6.501E-02	2.359E-02	2.359E-02	2.359E-02	7.180E-01	Heater	Gas	0.000E+00	1.625E-02	1.625E-02	4.876E-02	4.876E-02
TR121	Cooling Tow er	589065.78	6728699.12	40	0.000E+00	0.000E+00	2.877E-02	2.877E-02	0.000E+00	0.000E+00	0.000E+00	0.000E+00	Cooling Tow er	N/A	0.000E+00	0.000E+00	0.000E+00	2.877E-02	2.877E-02
TES_SHP	Tesoro Tanker	587369.12	6728656.39	0	6.405E+00	2.800E-03	3.085E-01	1.349E-04	4.272E-01	4.272E-01	1.868E-04	5.488E-01	Generator	Diesel	0.000E+00	2.658E-01	2.670E-01	4.272E-02	4.146E-02

Left at permit emissions since Actuals w ere not available from ADEC point source reporting

Model ID	Point Sources Description	Stack Parameters				1988	1979	1982	2013	install/ mod date from permit
		Stack Ht. (m)	Exit Temp. (K)	Exit Vel. (m/sec)	Stack Diam. (m)	Consumes NO ₂ Increment	Consumes SO ₂ Increment	Consumes PM ₁₀ Increment	Consumes PM _{2.5} Increment	
TR1	Crude Heater H-101A, Unit 0001	15.85	602	6.71	1.52	No	No	No	No	1969
TR2	Crude Heater H-101B, Unit 0002	26.52	531	6.10	1.22	Yes	Yes	Yes	No	1977/1997
TR3_5	Pow erformer Preheater H-201, Unit 0003 - 0005	32.31	730	4.27	2.13	No	No	No	No	1975
TR6	Pow erformer Reheater H-204, Unit 0006	46.33	533	6.10	1.52	No	Yes	No	No	1980
TR7	Pow erformer Reheater H-205, Unit 0007	46.33	533	6.10	1.52	No	Yes	No	No	1980
TR8	Hydrocracker Recycle Gas Heater, H-401, Unit 0008	25.91	532	5.18	1.22	Yes	Yes	Yes	No	1981/1989
TR9	Hydrocracker Recycle Gas Heater, H-402, Unit 0009	23.47	509	3.05	1.22	Yes	Yes	Yes	No	1981/1989
TR10	Hydrocracker Fractionater Reboiler, H-403, Unit 0010	22.86	564	7.62	1.22	Yes	Yes	Yes	No	1997
TR11	Hydrocracker Fractionater Reboiler, H-404, Unit 0011	23.47	561	5.49	1.52	Yes	Yes	Yes	No	1981/1989
TR12	Hot Oil Heater, H-609, Unit 0012	16.76	553	10.67	0.91	No	No	No	No	1969
TR15	Fired Steam Generator, H-701, Unit 0015	12.19	556	9.14	0.61	No	No	No	No	1969
TR16	Fired Steam Generator, H-702, Unit 0016	12.19	556	9.14	0.61	No	No	No	No	1969
TR17	Natural Gas Supply Heater, H-704, Unit 0017	4.88	600	65.84	0.12	No	Yes	Yes	No	1985
TR18	Fired Steam Generator, H-801, Unit 0018	12.19	450	8.53	0.61	No	Yes	No	No	1980
TR19	Hot Glycol Heater, H-802, Unit 0019	4.57	450	2.44	0.91	No	Yes	No	No	1980
TR20	Hydrogen Reformer Furnace, H-1001, Unit 0020	21.34	446	21.03	1.22	No	Yes	No	No	1981
TR21_26	Heaters, H-1101-1106, Units 0021-0026 (common stack)	30.48	450	0.91	0.91	No	Yes	Yes	No	1985
TR27	Prip Absorber Feed Furnace, H-1201/1203, Unit 0027	14.02	589	0.61	0.91	No	Yes	Yes	No	1986
TR28	Prip Recycle H2 Furnace, H-1202, Unit 0028	15.85	490	2.74	0.91	No	Yes	Yes	No	1986
TR29	Vacuum Tow er Heater, H-1701, Unit 0029	23.16	477	10.67	1.22	Yes	Yes	Yes	No	1994/2006
TR32	Solar Centaur Turbine, GT-1400	8.53	433	22.56	1.22	Yes	Yes	Yes	Yes	1988/2013?
TR33	Solar Centaur Turbine, GT-1410	8.53	433	22.56	1.22	Yes	Yes	Yes	Yes	1988/2013?
TR34	Electrical Generator CAT 3412, EG-704 Unit 0034	7.00	600	48.77	0.30	Yes	Yes	Yes	No	1989
TR35	Stew art-Stevens Generator, EG-801, Unit 0035	3.05	600	10.67	0.30	No	No	No	No	1969
TR36	North Caterpillar CAT G399, P-605A, Unit 0036	4.57	600	32.00	0.30	No	No	No	No	1969
TR37	South Caterpillar CAT G399, P-605B, Unit 0037	6.10	600	32.00	0.30	No	No	No	No	1969
TR38	North Cummins NHS6-1F, P-708A, Unit 0038	3.66	600	18.29	0.03	No	No	No	No	1969
TR40	Upper Tank Farm CAT 3412DT, P-708C, Unit 0040	3.66	600	39.29	0.240	Yes	Yes	Yes	No	1990
TR41	Cooling Tow er CAT G333. P-719C, Unit 0041	2.44	600	10.36	0.30	No	No	No	No	1969
TR42	Refinery Flare, J-801, Unit 0042	30.48	1273	20.00	0.305	No	Yes	No	No	1981
TR43	SRU Flare, Unit 0043	31.39	1273	20.00	1.52	No	Yes	Yes	No	1983
TR44	Soil Vapor Extraction Unit, E77 SVE/TO, Unit 0044	3.05	1061	1.83	0.30	Yes	Yes	Yes	No	2001/2002
TR45	Soil Vapor Extraction Unit, LTF SVE, Unit 0045	2.44	1061	1.22	0.91	Yes	Yes	Yes	No	2002
TR118	DDU Fractionator Reboiler, H1602 Unit 118	26.82	580	5.79	1.22	Yes	Yes	Yes	No	2007
TR119	H-1801-Naptha Splitter Reboiler Heater	26.82	580	5.79	1.22	Yes	Yes	Yes	No	2010
TR121	Cooling Tow er	9.14	272	0.30	6.10	Yes	Yes	Yes	No	2012
TES_SHP	Tesoro Tanker	45	589	4.2	1.68	No	No	No	No	1969

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Agrium – Kenai Nitrogen Operations Plant – Actual Emissions

Model	SOURCE	Location	Emissions (g/sec)																	
		Base Elev	NO _x (1-hr)	NO2 Annual	PM _{2.5} (24-hr)	PM2.5 Annual	SO2 1HR (lb/hr, from report)	SO ₂ (1-hr)	SO ₂ (3-hr, 24hr)	SO2 Ann (tpy, from report)	SO2 Annual (g/sec)	CO (lb/hr, from report)	CO (g/sec)	Equip Type	Fuel Type	PMF/SOIL	EC - PM2.5	EC - PM10	SOA - PM2.5	SOA - PM10
			(g/sec)	(g/sec)	(g/sec)	(g/sec)	(g/sec)	(g/sec)								(g/sec)	(g/sec)	(g/sec)	(g/sec)	(g/sec)
ID	DESCRIPTION	(m)	(g/sec)	(g/sec)	(g/sec)	(g/sec)	(g/sec)	(g/sec)		(tpy, from report)	(g/sec)	(lb/hr, from report)	(g/sec)			(g/sec)	(g/sec)	(g/sec)	(g/sec)	(g/sec)
AG_11	Ammonia Tank Storage System Flare	39.6	1.260E-02	1.064E-02	1.134E-03	1.151E-03	0.0	9.264E-05	9.264E-05	3.220E-03	9.264E-05	5.000E-02	6.300E-03	Flare	Gas	0.000E+00	2.835E-04	2.835E-04	8.505E-04	8.505E-04
AG_12	Primary Reformer	39.6	3.402E+00	3.403E+00	1.273E+00	1.269E+00	0.8	1.008E-01	1.008E-01	3.500E+00	1.007E-01	5.750E+01	7.245E+00	Boiler	Gas	0.000E+00	3.182E-01	3.182E-01	9.545E-01	9.545E-01
AG_13	Startup Heater	39.6	0.000E+00	2.848E-02	1.008E-01	2.158E-03	0.0	0.000E+00	1.726E-04	6.000E-03	1.726E-04	8.000E-01	1.008E-01	Heater	Gas	0.000E+00	2.520E-02	2.520E-02	7.560E-02	7.560E-02
AG_14	CO2 Vent	39.6	0.000E+00	0.000E+00	0.000E+00	0.000E+00	--	0.000E+00	0.000E+00	--	0.000E+00	1.270E+01	1.600E+00							
AG_16	Amine Fat Flasher Vent	39.6	0.000E+00	0.000E+00	0.000E+00	0.000E+00	--	0.000E+00	0.000E+00	--	0.000E+00	4.600E+00	5.796E-01							
AG_19	H2 Vent Stack (dry gas vent)	39.6	0.000E+00	0.000E+00	0.000E+00	0.000E+00	--	0.000E+00	0.000E+00	--	0.000E+00	1.269E+02	1.599E+01							
AG_22	Plants 4 and 5 Small Flare	39.6	1.071E-02	1.070E-02	1.172E-03	1.179E-03	0.0	9.264E-05	9.264E-05	3.220E-03	9.264E-05	2.000E+00	2.520E-01	Flare	Gas	0.000E+00	2.930E-04	2.930E-04	8.789E-04	8.789E-04
AG_23	Plants 4 and 5 Emergency Flare	39.6	3.402E-03	5.753E-03	3.780E-04	3.768E-04	0.0	2.963E-05	2.963E-05	1.030E-03	2.963E-05	6.000E-01	7.560E-02	Flare	Gas	0.000E+00	9.450E-05	9.450E-05	2.835E-04	2.835E-04
AG_35	Granulator A/B Scrubber Exhaust Vent Stack	39.6	0.000E+00	0.000E+00	1.260E+00	1.260E+00	--	0.000E+00	0.000E+00	--	--	--	0.000E+00	Cooling Tow er	N/A	0.0	0.0	0.0	1.3	1.3
AG_36	Granulator C/D Scrubber Exhaust Vent Stack	39.6	0.000E+00	0.000E+00	1.260E+00	1.260E+00	--	0.000E+00	0.000E+00	--	--	--	0.000E+00	Cooling Tow er	N/A	0.0	0.0	0.0	1.3	1.3
AG_40W	Cooling Tow er W	39.6	0.000E+00	0.000E+00	8.820E-05	8.342E-05	--	0.000E+00	0.000E+00	--	--	--	0.000E+00	Cooling Tow er	N/A	0.0	0.0	0.0	0.0	0.0
AG_40E	Cooling Tow er E	39.6	0.000E+00	0.000E+00	8.820E-05	8.342E-05	--	0.000E+00	0.000E+00	--	--	--	0.000E+00	Cooling Tow er	N/A	0.0	0.0	0.0	0.0	0.0
AG_44	Package Boiler	39.6	3.024E-01	3.049E-01	2.268E-01	2.273E-01	0.1	1.726E-02	1.726E-02	6.000E-01	1.726E-02	9.000E+00	1.134E+00	Boiler	Gas	0.000E+00	5.670E-02	5.670E-02	1.701E-01	1.701E-01
AG_47C	Urea Warehouse/Transfer (stack) °	39.6	0.000E+00	0.000E+00	3.654E-03	3.452E-04	--	0.000E+00	0.000E+00	--	--	--	0.000E+00	Cooling Tow er	N/A	0.0	0.0	0.0	0.0	0.0
AG_47D	Urea Transfer °	0.0	0.000E+00	0.000E+00	3.780E-03	3.740E-04	--	0.000E+00	0.000E+00	--	--	--	0.000E+00	Cooling Tow er	N/A	0.0	0.0	0.0	0.0	0.0
AG_48	Package Boiler	39.6	3.024E-01	3.049E-01	2.268E-01	2.273E-01	0.1	1.726E-02	1.726E-02	6.000E-01	1.726E-02	9.000E+00	1.134E+00	Boiler	Gas	0.000E+00	5.670E-02	5.670E-02	1.701E-01	1.701E-01
AG_49	Package Boiler	39.6	3.024E-01	3.049E-01	2.268E-01	2.273E-01	0.1	1.726E-02	1.726E-02	6.000E-01	1.726E-02	9.000E+00	1.134E+00	Boiler	Gas	0.000E+00	5.670E-02	5.670E-02	1.701E-01	1.701E-01
AG_50	Waste Heat Boiler	39.6	0.000E+00	2.733E-01	7.812E-02	7.623E-02	0.03	3.780E-03	3.780E-03	1.300E-01	3.740E-03	5.500E+00	6.930E-01	Boiler	Gas	0.000E+00	1.953E-02	1.953E-02	5.859E-02	5.859E-02
AG_51	Waste Heat Boiler	39.6	2.797E-01	2.796E-01	7.812E-02	7.825E-02	0.03	3.780E-03	3.780E-03	1.300E-01	3.740E-03	5.500E+00	6.930E-01	Boiler	Gas	0.000E+00	1.953E-02	1.953E-02	5.859E-02	5.859E-02
AG_52	Waste Heat Boiler	39.6	2.797E-01	2.796E-01	7.812E-02	7.825E-02	0.03	3.780E-03	3.780E-03	1.300E-01	3.740E-03	5.500E+00	6.930E-01	Boiler	Gas	0.000E+00	1.953E-02	1.953E-02	5.859E-02	5.859E-02
AG_53	Waste Heat Boiler	39.6	2.797E-01	2.796E-01	7.812E-02	7.825E-02	0.03	3.780E-03	3.780E-03	1.300E-01	3.740E-03	5.500E+00	6.930E-01	Boiler	Gas	0.000E+00	1.953E-02	1.953E-02	5.859E-02	5.859E-02
AG_54	Waste Heat Boiler	39.6	2.797E-01	2.796E-01	7.812E-02	7.825E-02	0.03	3.780E-03	3.780E-03	1.300E-01	3.740E-03	5.500E+00	6.930E-01	Boiler	Gas	0.000E+00	1.953E-02	1.953E-02	5.859E-02	5.859E-02
AG_55	Solar Turbine/Generator Set	39.6	2.482E+00	5.782E-02	0.000E+00	7.336E-04	0.65	8.631E-02	8.631E-02	3.000E+00	8.631E-02	2.050E+01	2.583E+00	Turbine	Gas	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00
AG_65	Diesel Fired Well Pump	39.6	2.873E-02	2.873E-02	1.008E-01	2.023E-03	0.8	2.014E-03	2.014E-03	7.000E-02	2.014E-03	2.600E+00	3.276E-01	Pump	Diesel	0.000E+00	8.684E-02	8.725E-02	1.396E-02	1.355E-02
AG_66A	Gasoline Fired Firew ater Pump °	34.1	4.133E-03	4.133E-03	2.205E-03	2.537E-04	0.09	2.135E-04	1.134E-02	7.420E-03	2.135E-04	2.100E+00	2.646E-01	Pump	Gas	0.000E+00	1.079E-03	1.079E-03	1.126E-03	1.126E-03
AG_66B	Gasoline Fired Firew ater Pump °	34.1	4.133E-03	4.133E-03	2.205E-03	2.537E-04	0.09	2.135E-04	1.134E-02	7.420E-03	2.135E-04	2.210E+00	2.785E-01	Pump	Gas	0.000E+00	1.079E-03	1.079E-03	1.126E-03	1.126E-03
ASHIPSTK	Ammonia Vessel (900 kW) °	0.0	7.299E+00	5.198E-01	1.273E-01	8.918E-03	0.98	1.230E-01	1.230E-01	3.046E-01	8.764E-03	6.640E+00	8.366E-01	Generator	Diesel	0.000E+00	1.096E-01	1.102E-01	1.762E-02	1.710E-02
USHIPSTK	Urea Vessel (240 kW) °	0.0	9.727E-01	2.822E-01	1.638E-02	4.890E-03	0.26	3.281E-02	3.281E-02	4.077E-01	1.173E-02	1.770E+00	2.230E-01	Generator	Diesel	0.000E+00	1.411E-02	1.418E-02	2.268E-03	2.201E-03
	HOMER ELECTRIC IS NOT PSD INCRMENT SOURCE																			
HOM_EL	Frame 6 Gas Turbine	39.6	1.309E+01	1.309E+01	3.452E-01	3.45E-01		1.726E-01	1.726E-01	6.00E+00	1.726E-01		5.75E-02	Turbine	Gas	0.000E+00	9.938E-02	9.938E-02	2.458E-01	2.458E-01

Notes:

a Location, emissions, and stack parameters obtained from dispersion modeling information submitted to ADEC supporting Agrium permit application (Agrium 2014).

b SO₂ emissions for vessels based on AP-42 Chapter 3.4 (per Agrium Modeling Report, 2014), assuming 0.1% S and 624 hrs/yr for the ammonia vessel and 3132 hrs/yr for the Urea vessel.

c Horizontal stack.

horizontal sources

Actual emissions from NEI Database

*some annual emission rates are higher than 1 hr rates due to scenarios Agrium modeled

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Model	SOURCE	Stack Parameters				PM ₁₀ (24-hr)	PM ₁₀ (annual)	NO2	Horiz
		Stack Ht.	Exit Temp	Exit Vel	Stack Diam				
ID	DESCRIPTION	(m)	(K)	(m/sec)	(m)	(g/sec)	(g/sec)	Ratio	
AG_11	Ammonia Tank Storage System Flare	9.14	394.26	45.72	0.40	1.134E-03	1.151E-03	0.50	NO
AG_12	Primary Reformer	30.48	526.48	24.40	3.66	6.363E-01	1.269E+00	0.50	NO
AG_13	Startup Heater	27.43	1033.15	13.53	1.83	1.008E-01	2.158E-03		CAP
AG_14	CO2 Vent	46.94	348	26.91	0.53	0.000E+00	0.000E+00		
AG_16	Amine Fat Flasher Vent	70.0	366.5	12.3	22.5	0.000E+00	0.000E+00		
AG_19	H2 Vent Stack (dry gas vent)	46.0	373.2	20.0	8.0	0.000E+00	0.000E+00		
AG_22	Plants 4 and 5 Small Flare	74.98	922.04	1.09	0.61	1.172E-03	1.179E-03	0.50	NO
AG_23	Plants 4 and 5 Emergency Flare	74.98	922.04	121.92	1.68	3.780E-04	3.768E-04	0.50	NO
AG_35	Granulator A/B Scrubber Exhaust Vent Stack	42.67	449.82	11.50	2.29	1.260E+00	1.260E+00		NO
AG_36	Granulator C/D Scrubber Exhaust Vent Stack	42.67	449.82	11.50	2.29	1.260E+00	1.260E+00		NO
AG_40W	Cooling Tower W	20.57	288.71	2.80	10.36	1.449E-02	1.424E-02		NO
AG_40E	Cooling Tower E	20.57	288.71	2.80	10.36	1.449E-02	1.424E-02		NO
AG_44	Package Boiler	30.48	422.04	12.61	1.83	2.268E-01	2.273E-01	0.10	NO
AG_47C	Urea Warehouse/Transfer (stack) ^c	9.91	-0.10	11.48	0.61	1.008E-02	1.007E-03		HOR
AG_47D	Urea Transfer ^c	24.38	-0.10	4.85	0.61	1.071E-02	1.064E-03		HOR
AG_48	Package Boiler	30.48	422.04	10.75	1.98	2.268E-01	2.273E-01	0.10	NO
AG_49	Package Boiler	30.48	422.04	10.75	1.98	2.268E-01	2.273E-01	0.10	NO
AG_50	Waste Heat Boiler	30.48	416.48	17.88	1.22	7.812E-02	7.623E-02		NO
AG_51	Waste Heat Boiler	30.48	416.48	17.88	1.22	7.812E-02	7.825E-02	0.30	NO
AG_52	Waste Heat Boiler	30.48	416.48	17.88	1.22	7.812E-02	7.825E-02	0.30	NO
AG_53	Waste Heat Boiler	30.48	416.48	17.88	1.22	7.812E-02	7.825E-02	0.30	NO
AG_54	Waste Heat Boiler	30.48	416.48	17.88	1.22	7.812E-02	7.825E-02	0.30	NO
AG_55	Solar Turbine/Generator Set	18.29	608.15	40.21	1.01	0.000E+00	7.336E-04	0.30	NO
AG_65	Diesel Fired Well Pump	9.14	533.15	16.17	0.30	1.008E-01	2.023E-03	0.22	HOR
AG_66A	Gasoline Fired Firewater Pump ^c	2.08	699.82	29.11	0.10	2.205E-03	2.537E-04	0.22	HOR
AG_66B	Gasoline Fired Firewater Pump ^c	2.08	699.82	29.11	0.10	2.205E-03	2.537E-04	0.22	HOR
ASHIPSTK	Ammonia Vessel (900 kW) ^b	39.00	613.15	69.72	0.25	1.307E+00	9.320E-02	0.22	NO
USHIPSTK	Urea Vessel (240 kW) ^b	29.00	358.15	6.14	0.30	1.739E-01	5.063E-02	0.22	NO
	HOMER ELECTRIC IS NOT PSD INCRMENT SOURCE								
HOM_EL	Frame 6 Gas Turbine	30.78	403.15	19.81	3.35	3.452E-01	3.45E-01	0.30	NO

- Notes:
- a Location, emissions, and stack parameters obtained from dispersion modeling information submitted to ADEC supporting Agrium permit application (Agrium 2014).
 - b SO₂ emissions for vessels based on AP-42 Chapter 3.4 (per Agrium Modeling Report, 2014), assuming 0.1% S and 624 hrs/yr for the ammonia vessel and 3132 hrs/yr for the Urea vessel.
 - c Horizontal stack.

horizontal sources

Actual emissions from NEI Database

*some annual emission rates are higher than 1 hr rates due to scenarios Agrium modeled

Volume Sources

Model ID	SOURCE DESCRIPTION	Location ^a	Emissions ^a (g/sec)																
		Base Elev (m)	NO _x (1-hr) (g/sec)	Annual* (g/sec)	PM _{2.5} (24-hr) (g/sec)	Annual (g/sec)	1HR (lb/hr)	SO ₂ (1-hr) (g/sec)		SO2 Annual		CO			PMF/SOIL (g/sec)	EC - PM2.5 (g/sec)	EC - PM10 (g/sec)	SOA - PM2.5 (g/sec)	SOA - PM10 (g/sec)
			Equip Type	Fuel Type															
47B	FUGITIVE DUST	39.60	--	--	1.890E-02	2.01E-03		--	--	--	--			1.890E-02		0.000E+00		0.000E+00	
47	FUGITIVE DUST	0.00	--	--	4.725E-02	4.72E-03		--	--	--	--			4.725E-02		0.000E+00		0.000E+00	

Model ID	SOURCE DESCRIPTION	Stack Parameters ^a			PM ₁₀ (24-hr) (g/sec)	PM ₁₀ (annual) (g/sec)
		Rel.Ht. (m)	Syinit (m)	Szinit (m)		
47B	FUGITIVE DUST	14.02	11.63	9.91	5.42E-02	5.47E-04
47	FUGITIVE DUST	18.29	3.54	2.83	1.34E-01	1.34E-02

Kenai Liquefied Natural Gas (LNG) Plant

Model IDSource Description		Location				Emissions (g/sec)														
		UTM X	UTM Y	lc-x	lc-y	Base Elev. (m)	NOx (1-hr)	NOx (ann)	PM _{2.5} /PM ₁₀ (24-hr)	PM _{2.5} / PM ₁₀ (ann)	SO ₂ (1-hr, 3hr, 24hr)	SO ₂ (ann)	CO (1hr, 8hr)	Equip Type	Fuel Type	PMF/SOIL	EC - PM2.5	EC - PM10	SOA - PM2.5	SOA - PM10
COMP_151	GE Frame 5 - Cycle #151	588333.7	6728012.7	-21.0	186.9	34.9	3.170E-01	3.17E-01	8.342E-03	8.34E-03	5.753E-04	5.75E-04	1.03E-01	Turbine	Gas	0.000E+00	2.402E-03	2.402E-03	5.941E-03	5.941E-03
COMP_152	GE Frame 5 - Cycle #152	588326.4	6728012.5	-21.0	186.9	34.9	5.150E+00	5.15E+00	1.349E-01	1.35E-01	8.342E-03	8.34E-03	1.68E+00	Turbine	Gas	0.000E+00	3.884E-02	3.884E-02	9.608E-02	9.608E-02
COMP_251	GE Frame 5 - Cycle #251	588363.0	6728013.4	-21.0	186.9	34.9	1.786E+00	1.79E+00	3.912E-02	3.91E-02	2.301E-03	2.30E-03	4.85E-01	Turbine	Gas	0.000E+00	1.126E-02	1.126E-02	2.786E-02	2.786E-02
COMP_252	GE Frame 5 - Cycle #252	588355.7	6728013.2	-21.0	186.9	34.9	4.168E+00	4.17E+00	9.119E-02	9.12E-02	5.753E-03	5.75E-03	1.13E+00	Turbine	Gas	0.000E+00	2.625E-02	2.625E-02	6.494E-02	6.494E-02
COMP_351	GE Frame 5 - Cycle #351	588348.4	6728013.0	-21.0	186.9	34.9	7.465E-01	7.46E-01	1.899E-02	1.90E-02	1.151E-03	1.15E-03	2.36E-01	Turbine	Gas	0.000E+00	5.466E-03	5.466E-03	1.352E-02	1.352E-02
COMP_352	GE Frame 5 - Cycle #352	588341.0	6728012.9	-21.0	186.9	34.9	3.580E+00	3.58E+00	9.119E-02	9.12E-02	5.753E-03	5.75E-03	1.13E+00	Turbine	Gas	0.000E+00	2.625E-02	2.625E-02	6.494E-02	6.494E-02
COMP_701	SOLAR TAURUS 60	588319.1	6728012.3	-21.0	186.9	34.9	1.174E-01	1.17E-01	2.359E-02	2.36E-02	1.438E-03	1.44E-03	1.78E-02	Turbine	Gas	0.000E+00	6.791E-03	6.791E-03	1.680E-02	1.680E-02
BLR_501	BOILER 501	588412.2	6728019.6	-20.9	186.9	35.1	8.342E-02	8.34E-02	6.329E-03	6.33E-03	2.877E-04	2.88E-04	7.02E-02	Boiler	Gas	0.000E+00	1.582E-03	1.582E-03	4.746E-03	4.746E-03
BLR_502	BOILER 502	588417.4	6728019.7	-20.9	186.9	35.1	1.269E-01	1.27E-01	9.493E-03	9.49E-03	5.753E-04	5.75E-04	1.06E-01	Boiler	Gas	0.000E+00	2.373E-03	2.373E-03	7.120E-03	7.120E-03
BLR_511	BOILER 511	588422.6	6728019.9	-20.9	186.9	35.1	1.464E-01	1.46E-01	1.122E-02	1.12E-02	5.753E-04	5.75E-04	1.23E-01	Boiler	Gas	0.000E+00	2.805E-03	2.805E-03	8.414E-03	8.414E-03
E_GEN	Caterpillar D379 Emergency Generator	588407.5	6728012.6	-20.9	186.9	35.0	7.479E-03	7.48E-03	5.753E-04	5.75E-04	0.000E+00	0.00E+00	1.73E-03	Generator	Diesel	0.000E+00	4.957E-04	4.980E-04	7.968E-05	7.731E-05
FW_PUMP2	Caterpillar D3406 Firew ater Pump #2	588246.7	6727999.8	-21.1	186.8	35.0	4.315E-03	4.31E-03	2.877E-04	2.88E-04	0.000E+00	0.00E+00	8.63E-04	Generator	Diesel	0.000E+00	2.478E-04	2.490E-04	3.984E-05	3.866E-05
FW_PUMP3	Caterpillar D3406 Firew ater Pump #3	588246.6	6728001.5	-21.1	186.8	35.0	4.027E-03	4.03E-03	2.877E-04	2.88E-04	0.000E+00	0.00E+00	8.63E-04	Generator	Diesel	0.000E+00	2.478E-04	2.490E-04	3.984E-05	3.866E-05
FW_PUMP4	Caterpillar D3406 Firew ater Pump #4	588246.5	6728007.0	-21.1	186.8	35.0	3.164E-03	3.16E-03	2.877E-04	2.88E-04	0.000E+00	0.00E+00	5.75E-04	Generator	Diesel	0.000E+00	2.478E-04	2.490E-04	3.984E-05	3.866E-05
FLARE	Ground Flare	588187.6	6728327.0	-21.1	187.2	26.7	1.076E-01	1.08E-01	4.171E-02	4.17E-02	5.753E-04	5.75E-04	5.84E-01	Flare	Gas	0.000E+00	1.043E-02	1.043E-02	3.128E-02	3.128E-02
KSHP	Tanker	587510.4	6728052.6	-21.835	186.91	0.0	5.289E+00	1.040E+00	1.990E-01	4.364E-02	9.025E-01	2.698E-02	6.944E+00	Generator	Diesel	0.000E+00	1.715E-01	1.723E-01	2.756E-02	2.674E-02

Notes: horizontal/capped source
Location, emissions, and stack parameters obtained from **AERMOD_input_file_spreadsheet_04_26_2013.xls**
Emissions based on maximum short-term permitted limits, except w here noted.
It w as assumed that the tanker w as similar to vessels that w ill be used at the AKLNG facility. Therefore, the emissions and stack parameters used for the AKLNG carriers w ere also used for the Kenai vessel.

Model IDSource Description		Stack Parameters				Horiz/Cap?	1988	1982	2013?	1980	install date
		Stack Ht. (m)	Exit Temp. (K)	Exit Vel. (m/sec)	Stack Diam. (m)		no2	PM10	PM2.5	SO2	
COMP_151	GE Frame 5 - Cycle #151	19.51	589	22.90	2.134		No	No	No	No	1969
COMP_152	GE Frame 5 - Cycle #152	19.51	589	22.90	2.134		No	No	No	No	1969
COMP_251	GE Frame 5 - Cycle #251	19.51	589	22.90	2.134		No	No	No	No	1969
COMP_252	GE Frame 5 - Cycle #252	19.51	589	22.90	2.134		No	No	No	No	1969
COMP_351	GE Frame 5 - Cycle #351	19.51	589	22.90	2.134		No	No	No	No	1969
COMP_352	GE Frame 5 - Cycle #352	19.51	589	22.90	2.134		No	No	No	No	1969
COMP_701	SOLAR TAURUS 60	19.51	776	98.41	0.813		Y	Y	No	Y	2006
BLR_501	BOILER 501	19.81	589	9.10	0.975	Cap	No	No	No	No	1969
BLR_502	BOILER 502	19.81	589	9.10	0.975	Cap	No	No	No	No	1969
BLR_511	BOILER 511	19.81	589	9.10	0.975	Cap	No	No	No	No	1969
E_GEN	Caterpillar D379 Emergency Generator	6.25	600	39.29	0.244		No	No	No	No	1969
FW_PUMP2	Caterpillar D3406 Firewater Pump #2	3.96	600	39.29	0.244	Horiz	Y	Y	No	Y	1992
FW_PUMP3	Caterpillar D3406 Firewater Pump #3	3.96	600	39.29	0.244	Horiz	Y	Y	No	Y	1992
FW_PUMP4	Caterpillar D3406 Firewater Pump #4	3.96	600	39.29	0.244	Horiz	Y	Y	No	Y	1992
FLARE	Ground Flare	2.33	1273	20.00	0.451	Horiz	No	No	No	No	1992
KSHP	Tanker	45.00	589	4.2	1.68		No	No	No	No	1969

Notes: horizontal/capped source

Location, emissions, and stack parameters obtained from **AERMOD_input_file_spreadsheets_04_26_2013.xls**

Emissions based on maximum short-term permitted limits, except where noted.

It was assumed that the tanker was similar to vessels that will be used at the AKLNG facility. Therefore, the emissions and stack parameters used for the AKLNG carriers were also used for the Kenai vessel.

Additional Offsite Point Sources – Actual Emissions

SRCID	Source Description	Z(m)	NOx (1-hr & Annual)	PM (24-hr & Annual)	SO2 (All avg per)	CO	Equip Type	Fuel Type	PMF/SOIL	EC - PM2.5	EC - PM10	SOA - PM2.5	SOA - PM10	Hs (m)	Ts (K)	Vs (m/sec)	Ds(m)	NO2 Ratio	UTM X	UTM Y	NO2	PM10	PM2.5	SO2
13001	Hilcorp Middle Ground Shoal Onshore Facility	50.0	4.79E-01	3.31E-02	5.20E-03	1.40E-01	Turbine	Gas	0.000E+00	9.529E-03	9.529E-03	2.357E-02	2.357E-02	5.00	500	20.00	1.00	0.50	589539.4	6734383.7	y	y	n	y
15001	Hilcorp Platform C Middle Ground Shoal	0.0	9.88E+00	1.21E-01	2.47E-01	1.01E+01	Turbine	Gas	0.000E+00	3.478E-02	3.478E-02	8.604E-02	8.604E-02	27.50	850	25.00	1.00	0.50	581223.4	6736992.7	y	y	n	y
18002	Bernice Lake Power Station - Natural Gas Turbine 2	35.0	6.99E-01	1.44E-02	2.88E-04	1.78E-01	Turbine	Gas	0.000E+00	4.141E-03	4.141E-03	1.024E-02	1.024E-02	15.20	428	18.50	2.30	0.50	587989.4	6729683.7	n	n	n	n
18003	Bernice Lake Power Station - Natural Gas Turbine 3	35.0	1.96E-01	5.47E-03	0.00E+00	2.30E-01	Turbine	Gas	0.000E+00	1.573E-03	1.573E-03	3.892E-03	3.892E-03	10.80	760	21.10	3.90	0.50	587989.4	6729683.7	n	n	n	n
18004	Bernice Lake Power Station - Natural Gas Turbine 4	35.0	1.63E+00	3.74E-02	8.63E-04	1.12E+00	Turbine	Gas	0.000E+00	1.077E-02	1.077E-02	2.663E-02	2.663E-02	10.80	760	21.10	3.90	0.50	587989.4	6729683.7	n	y	n	y
50001	KPL Marine Loading Terminal - Firewater Pump 1	30.0	4.03E-03	0.00E+00	0.00E+00	5.75E-04	Pump	Diesel	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	3.70	600	67.00	0.10	0.50	588092.5	6728971.4	y	y	n	y
50002	KPL Marine Loading Terminal - Firewater Pump 2	30.0	3.16E-03	2.88E-04	0.00E+00	2.88E-04	Pump	Diesel	0.000E+00	2.478E-04	2.490E-04	3.984E-05	3.866E-05	3.70	600	67.00	0.10	0.50	588092.5	6728967.4	y	y	n	y

Additional Facilities – Actual Emissions (RFD sources are in PTE)

SRCID	Model ID	Volume Sources Description	Location ^a			2011 Emissions (g/sec) ^b														
			Longitude	Latitude	Base Elev. (m)	NOx (1-hr)	NOx (annual)	PM _{2.5} (24-hr)	PM _{2.5} (annual)	PM ₁₀ (24-hr)	PM ₁₀ (annual)	SO ₂ (1-hr)	SO ₂ (3-hr & 24-hr)	SO ₂ (annual)	CO (1hr, 8hr)	PMF/SOIL ^d	EC - PM2.5 ^{e,g,h}	EC - PM10	SOA - PM2.5 ^{f,g,h}	SOA - PM10
vol_1	Bea	Beaver Creek Production Facility	-151.03	60.67	47.40	2.87	2.87	0.04	0.04	0.04	0.04	9.87	9.87	9.87	4.19	0.00	0.04	0.04	0.04	0.04
vol_1	Bel	Beluga River Pow er Plant	-151.05	61.19	27.30	99.58	99.58	2.74	2.74	2.77	2.77	0.76	0.76	0.76	25.22	0.00	3.07	3.13	2.42	2.42
vol_1	Bru	Bruce Platform	-151.33	60.83	0.00	3.09	3.09	0.05	0.05	0.05	0.05	0.00	0.00	0.00	3.60	0.00	0.06	0.06	0.04	0.04
vol_1	Cle	Clear Air Force Station	-149.13	64.31	166.80	6.46	6.46	0.04	0.04	0.03	0.03	5.88	5.88	5.88	3.66	0.00	0.06	0.16	0.01	0.01
	Dol	Dolly Varden Platform WITH KUUKPIK 5 RIG EMISSIONS	-151.63	60.81	0.00	5.76	5.76	0.21	0.21	0.21	0.21	3.92	3.92	3.92	3.53	0.00	0.24	0.24	0.16	0.16
	Dri	Drift River Terminal / Christy Lee Platform Aggregated Source	-152.15	60.57	0.30	2.22	2.22	0.03	0.03	0.03	0.03	0.12	0.12	0.12	0.27	0.00	0.06	0.06	0.00	0.00
	Geo	George Sullivan Plant Tw o	-149.72	61.23	108.40	52.28	52.28	1.08	1.08	1.08	1.08	0.01	0.01	0.01	12.12	0.00	1.19	1.19	0.97	0.97
	Gra	Grayling Platform WITH KUUKPIK 5 RIG EMISSIONS	-151.61	60.84	0.00	9.89	9.89	0.28	0.28	0.28	0.28	1.08	1.08	1.08	2.93	0.00	0.32	0.32	0.22	0.22
vol6	Sold	AE&EC - Soldonta Turbine	-151.00	60.50	74.00	7.06	7.06	1.06	1.06	1.06	1.06	0.35	0.35	0.35	6.33	0.00	0.31	0.31	0.76	0.76
vol6	Gude	Alaska Pipeline Co. - Gudenrath Compressor Station	-150.62	60.54	100.00	2.17	2.17	0.06	0.06	0.06	0.06	0.03	0.03	0.03	0.75	0.00	0.02	0.02	0.04	0.04
	Han	Hank Nikkels Plant One	-149.87	61.22	30.50	2.29	2.29	0.11	0.11	0.11	0.11	0.00	0.00	0.00	0.75	0.00	0.13	0.13	0.09	0.09
	Hea	Healy Pow er Plant	-148.95	63.85	449.20	9.08	9.08	0.80	0.80	0.80	0.80	13.24	13.24	13.24	9.53	0.00	1.48	1.48	0.11	0.11
	Ke1	Kenai Gas Field 14-6 Pad	-151.26	60.46	18.60	30.15	30.15	0.65	0.65	0.65	0.65	0.12	0.12	0.12	7.80	0.00	0.00	0.00	0.00	0.00
	Ke2	Kenai Gas Field 34-31 Pad	-151.27	60.48	16.20	2.66	2.66	0.05	0.05	0.05	0.05	0.03	0.03	0.03	0.91	1.00	0.00	0.00	0.00	0.00
	Kin	King Salmon Platform	-151.61	60.87	0.00	3.72	3.72	0.14	0.14	0.14	0.14	2.64	2.64	2.64	1.44	0.00	0.58	0.58	0.87	0.87
	LNG	LNG Plant #1	-150.08	61.43	42.00	6.18	6.18	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.88	1.00	0.58	0.58	0.87	0.87
	Pl1	Platform A	-151.50	60.80	0.00	9.15	9.15	0.14	0.14	0.14	0.14	1.00	1.00	1.00	6.34	0.00	0.01	0.01	0.01	0.01
	Pl2	Platform C, Middle Ground Shoal, Cook Inlet	-151.50	60.76	0.00	9.88	9.88	0.12	0.12	0.12	0.12	0.25	0.25	0.25	10.06	0.00	0.38	0.38	0.31	0.31
	Ste	Steelhead Platform	-151.60	60.83	0.00	5.24	5.24	0.23	0.23	0.23	0.23	0.01	0.01	0.01	1.58	0.00	0.11	0.12	0.10	0.10
	Sw a	Sw anson River Field	-150.86	60.73	44.00	30.82	30.82	0.48	0.48	0.48	0.48	0.00	0.00	0.00	5.78	0.00	0.08	0.08	0.07	0.07
	Ted	Ted Stevens Anchorage I	-150.02	61.18	26.50	65.44	65.44	1.71	1.71	1.77	1.77	6.26	6.26	6.26	113.68	0.00	0.68	0.74	1.03	1.03
	Tyo	Tyonek Platform	-150.95	61.07	0.00	4.37	4.37	0.09	0.09	0.09	0.09	0.00	0.00	0.00	3.11	0.00	0.54	0.54	0.42	0.42
	Val	Valdez Diesel Pow er Plant	-146.35	61.14	106.40	4.03	4.03	0.10	0.10	0.10	0.10	0.64	0.64	0.64	1.10	0.00	0.00	0.00	0.00	0.00

RFD Source - Emissions are PTE, not actuals

Notes:

a Locations based on 2011 NEI Database Average Point Source Longitude and Latitude

b Emissions based on Double the Actual Emissions from 2011 NEI Database.

1-hr, 3-hr, 8-hr, and 24-hr have been set equal to the annual emission rate for each pollutant. It is assumed that the same level of emissions from the facility are emitted throughout the year (8,760 hours). Specific maximum operating cases are not know n.

c All volume source plume assumed to be 10 m x 10 m x 10 m in size

Syinit assumed 4.3 from Table 3-1 in the AERMOD User's Guide for a single volume source

Syinit assumed 4.3 from Table 3-1 in the AERMOD User's Guide for an elevated source not on or adjacent to a building

d PMF/Soil Set Equal to 0 tpy with the assumption that the majority of the emitters within the Volume Sources are combustion-driven equipment.

e The Elemental Carbon (EC) is set equal to the PM Filterable emissions provided by the 2011 NEI Database

f The Secondary Organic Aerosols (SOA) are set equal to the PM Condensable emissions provided by the 2011 NEI Database

h Ted Stevens Anchorage I EC and SOA emissions calculated using AP42 filterable/condensable particulate matter speciation. The PM emissions were split into 4 equal parts to represent the possible equipment at the facility

	PM2.5 EC	PM2.5 SOA	PM10 EC	PM10 SOA
Mobile Source with Diesel Fuel	10%	90%	11%	89%
Generator with Diesel Fuel	86%	14%	87%	13%
Heater with Gas Fuel	25%	75%	25%	75%
Heater with Diesel Fuel	39%	61%	45%	55%

i The Solodonta Turbine and Gundenrath Compressor Station EC and SOA emissions calculated using AP42 filterable/condensable particulate matter speciation. The PM emissions were assumed to be based on gas-fired turbines as the main PM emission source

	PM2.5 EC	PM2.5 SOA	PM10 EC	PM10 SOA
Turbine with Gas Fuel	29%	71%	29%	71%

j The Kuukpik 5 Rig EC and SOA emissions calculated using AP42 filterable/condensable particulate matter speciation. The PM emissions were assumed to be based on diesel-fired generator as the main PM emission source

	PM2.5 EC	PM2.5 SOA	PM10 EC	PM10 SOA
Generator with Diesel Fuel	86%	14%	87%	13%

k Ted Stevens Anchorage I assumed to be all increment consuming

SRCID	Model ID	Volume Sources Description	Stack Parameters ^c				1988	1982	2013?	1979	Oldest Install Date	Newest Install Date
			Rel.Ht. (m)	Syinit (m)	Szinit (m)	NO2 Ratio	Increment Consuming NOx	Increment Consuming PM10	Increment Consuming PM2.5	Increment Consuming SO2		
vol_1	Bea	Beaver Creek Production Facility	10.0	2.33	2.33	0.5	Y	Y	N	Y	1973	2004
vol_1	Bel	Beluga River Pow er Plant	10.0	2.33	2.33	0.5	Y	Y	N	Y	1968	2011
vol_1	Bru	Bruce Platform	10.0	2.33	2.33	0.5	Y	Y	N	Y	1967	2008
vol_1	Cle	Clear Air Force Station	10.0	2.33	2.33	0.5	Y	Y	N	Y	1960	2012
	Dol	Dolly Varden Platform WITH KUUKPIK 5 RIG EMISSIONS	10.0	2.33	2.33	0.5	Y	Y	Y	Y		
	Dri	Drift River Terminal / Christy Lee Platform Aggregated Source	10.0	2.33	2.33	0.5	Y	Y	N	Y	1966	2008
	Geo	George Sullivan Plant Tw o	10.0	2.33	2.33	0.5	Y	Y	Y	Y	1975	2015
	Gra	Grayling Platform WITH KUUKPIK 5 RIG EMISSIONS	10.0	2.33	2.33	0.5	Y	Y	Y	Y		
vol6	Sold	AE&EC - Soldonta Turbine	10.0	2.33	2.33	0.5	Y	Y	Y	Y		
vol6	Gude	Alaska Pipeline Co. - Gudenrath Compressor Station	10.0	2.33	2.33	0.5	Y	Y	Y	Y		
	Han	Hank Nikkels Plant One	10.0	2.33	2.33	0.5	Y	Y	N	Y	1962	2011
	Hea	Healy Pow er Plant	10.0	2.33	2.33	0.5	Y	Y	N	Y	1967	1998
	Ke1	Kenai Gas Field 14-6 Pad	10.0	2.33	2.33	0.5	Y	Y	N	Y	1980	2004
	Ke2	Kenai Gas Field 34-31 Pad	11.0	2.33	2.56	1.5	Y	Y	N	Y	1985	2001
	Kin	King Salmon Platform	10.0	2.33	2.33	0.5	Y	Y	N	Y	1967	2006
	LNG	LNG Plant #1	11.0	2.33	2.56	1.5	Y	Y	N	Y	1998	2006
	P11	Platform A	10.0	2.33	2.33	0.5	Y	Y	Y	Y	1965	2013
	P12	Platform C, Middle Ground Shoal, Cook Inlet	10.0	2.33	2.33	0.5	Y	Y	Y	Y	1967	2013
	Ste	Steelhead Platform	10.0	2.33	2.33	0.5	Y	Y	N	Y	1986	2009
	Sw a	Sw anson River Field	10.0	2.33	2.33	0.5	Y	Y	N	Y	1962	2007
	Ted	Ted Stevens Anchorage I	10.0	2.33	2.33	0.5	Y	Y	Y	Y		
	Tyo	Tyonek Platform	10.0	2.33	2.33	0.5	Y	Y	N	Y	1968	2002
	Val	Valdez Diesel Pow er Plant	10.0	2.33	2.33	0.5	N	N	N	N	1966	1976
RFD Source - Emissions are PTE, not actuals												

Notes:

- a Locations based on 2011 NEI Database Average Point Source Longitude and Latitude
- b Emissions based on Double the Actual Emissions from 2011 NEI Database.

1-hr, 3-hr, 8-hr, and 24-hr have been set equal to the annual emission rate for each pollutant. It is assumed that the same level of emissions from the facility are emitted throughout the year (8,760 hours). Specific maximum operating cases are not know n.
- c All volume source plume assumed to be 10 m x 10 m x 10 m in size

Syinit assumed 4.3 from Table 3-1 in the AERMOD User's Guide for a single volume source

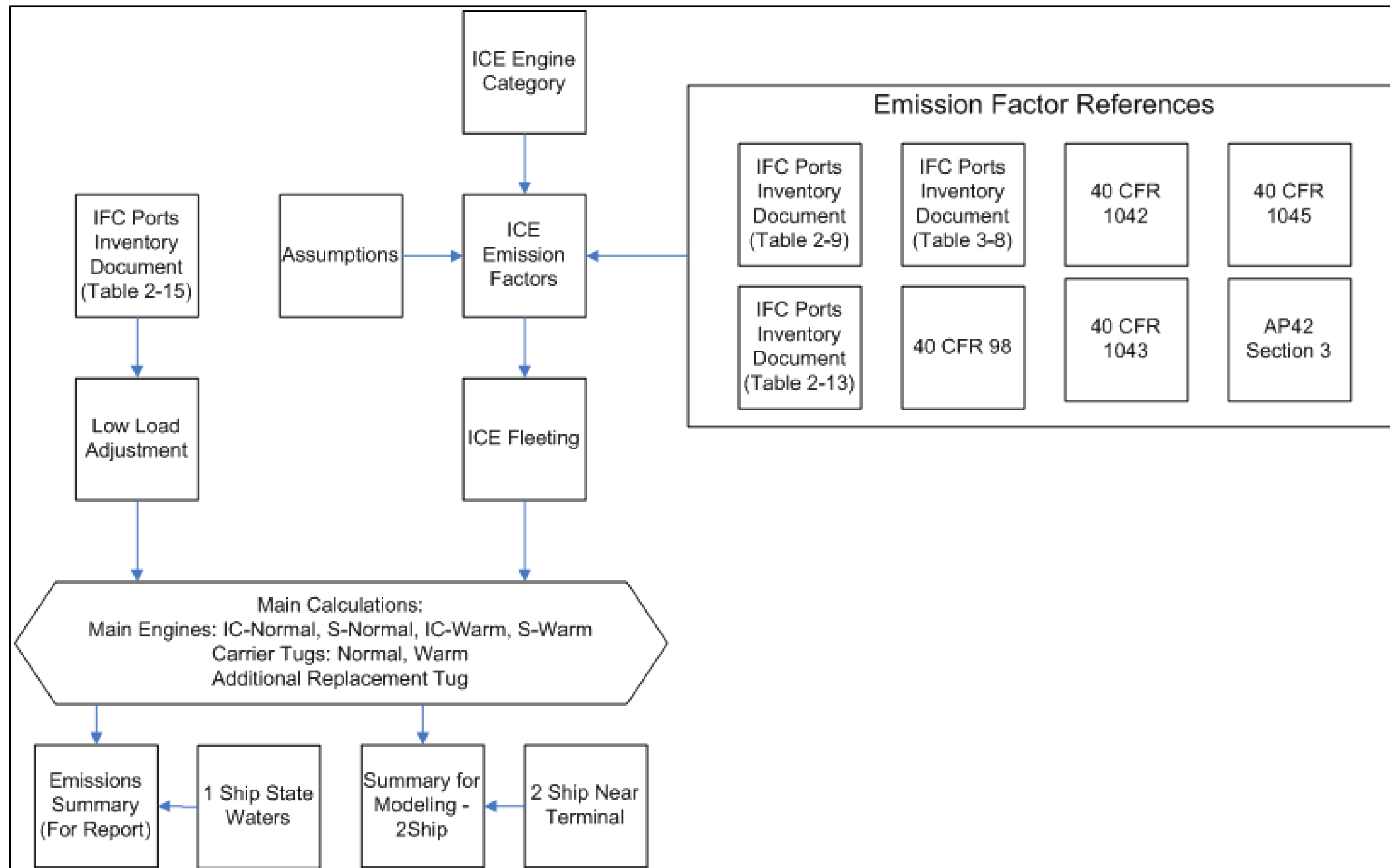
Syinit assumed 4.3 from Table 3-1 in the AERMOD User's Guide for an elevated source not on or adjacent to a building
- d PMF/Soil Set Equal to 0 tpy w ith the assumption that the majority of the emitters w ithin the Volume Sources are combustion-driven equipment.
- e The Elemental Carbon (EC) is set equal to the PM Filterable emissions provided by the 2011 NEI Database
- f The Secondary Organic Aerosols (SOA) are set equal to the PM Condensable emissions provided by the 2011 NEI Database
- h Ted Stevens Anchorage I EC and SOA emissions calculated using AP42 filterable/condensable particulate matter speciation. The PM emissions w ere split into 4 equal parts to represent the possible equipment at the facility

	PM2.5 EC	PM2.5 SOA	PM10 EC	PM10 SOA
Mobile Source w ith Diesel Fuel	10%	90%	11%	89%
Generator w ith Diesel Fuel	86%	14%	87%	13%
Heater w ith Gas Fuel	25%	75%	25%	75%
Heater w ith Diesel Fuel	39%	61%	45%	55%
- i The Solodonta Turbine and Gundenrath Compressor Station EC and SOA emissions calculated using AP42 filterable/condensable particulate matter speciation. The PM emissions w ere assumed to be based on gas-fired turbines as the main PM emission source

	PM2.5 EC	PM2.5 SOA	PM10 EC	PM10 SOA
Turbine w ith Gas Fuel	29%	71%	29%	71%
- j The Kuukpik 5 Rig EC and SOA emissions calculated using AP42 filterable/condensable particulate matter speciation. The PM emissions w ere assumed to be based on diesel-fired generator as the main PM emission source

	PM2.5 EC	PM2.5 SOA	PM10 EC	PM10 SOA
Generator w ith Diesel Fuel	86%	14%	87%	13%
- k Ted Stevens Anchorage I assumed to be all increment consuming

MEC-1 FLOW CHART OF CALCULATION COMPONENTS



MEC-2 ANNUAL MARINE OPERATION SUMMARY

Facility Throughput (Total)			
Annual Facility LNG Production	20	MTPA	(million tonnes per annum)
	20,000,000,000	kg/yr	
Hourly Facility LNG Production	2,283,105	kg/hr	
	455	kg/m3	Average assumed density of LNG
Annual Volumetric LNG Production	43,956,044	m3/yr	
Hourly Volumetric LNG Production	5,018	m3/hr	

LNG Carrier Breakdown of Facility Production						
	Total		Normal Arrival		Warm Arrival	
	Frequency	Flow Rate	Frequency	Flow Rate	Frequency	Flow Rate
Combustion Engine Carrier	98%	43,076,923	97%	41,784,615	3%	1,292,308
Steam Carrier	2%	879,121	97%	852,747	3%	26,374

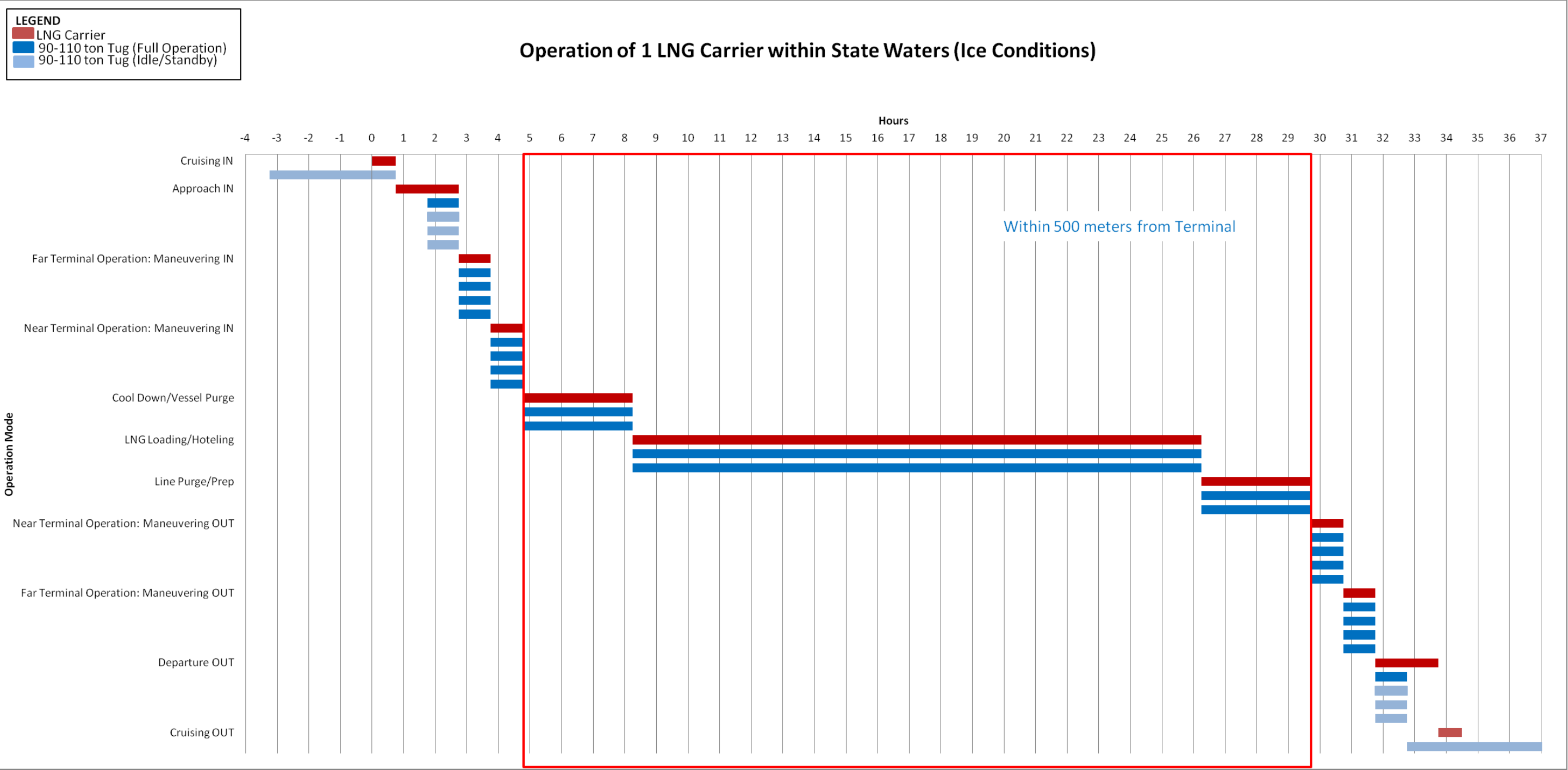
LNG Carrier Annual Calls			
	Size	No. of Normal Calls	No. of Warm Calls
Combustion Engine Carrier	216,000	193.45	5.98
Steam Carrier	216,000	3.95	0.12

MEC-3 ANNUAL TOTAL EMISSIONS SUMMARY

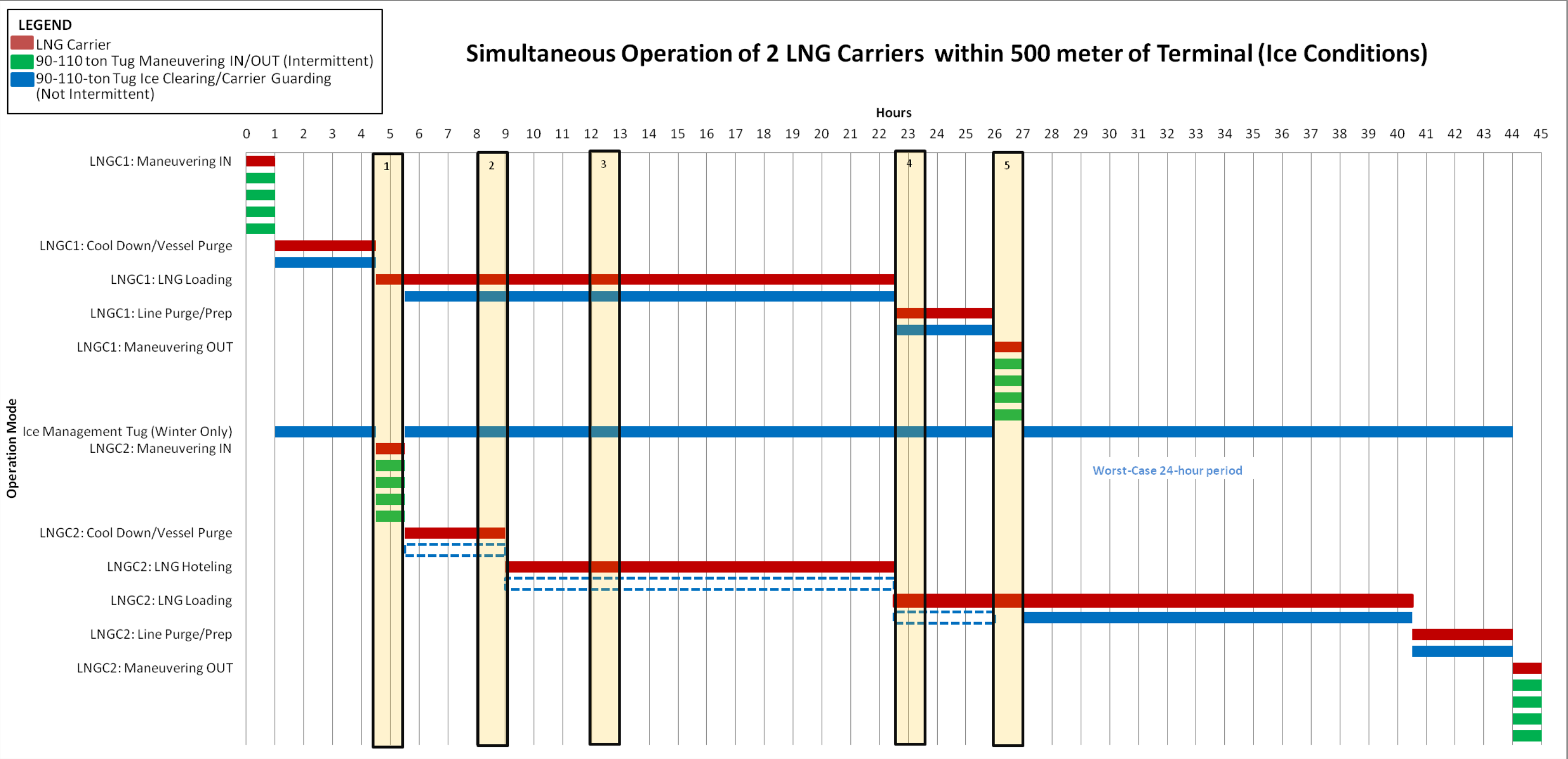
Weighted Average Exhaust Gas Emissions (lb/hr)									
Pollutant	IC Engine		Steam Engine		LNG Carrier Total	Carrier Tugs		Tug Total	Marine Inventory Total
	Normal Arrival	Warm Arrival	Normal Arrival	Warm Arrival		Normal Carrier Arrival	Warm Carrier Arrival		
NO _x	69	42	34	29	174	52	53	105	279
CO	76	49	4	4	133	161	164	325	458
VOC	27	16	2	2	47	6	6	12	59
PM ₁₀	3	2	3	3	10	2	2	4	13
PM _{2.5}	2	1	3	2	9	2	2	4	12
SO ₂	0	0	10	8	18	0	0	0	18
GHG (CO ₂ e) ¹	9,562	6,261	15,941	13,431	45,194	20,400	20,586	40,986	86,180
HAPs	0.04	0.03	0.05	0.04	0.15	0.08	0.08	0.16	0.31
Exhaust Gas Emissions (TPY) (tonnes/year for CO ₂ e)									
Pollutant	IC Engine		Steam Engine		LNG Carrier Total	Carrier Tugs		Tug Total	Marine Inventory Total
	Normal Arrival	Warm Arrival	Normal Arrival	Warm Arrival		Normal Carrier Arrival	Warm Carrier Arrival		
NO _x	260	11	3	0	274	100	6	106	380
CO	291	13	0	0	304	309	17	326	630
VOC	100	4	0	0	104	12	1	12	117
PM ₁₀	10	0	0	0	10	3	0	4	14
PM _{2.5}	9	0	0	0	9	3	0	4	13
SO ₂	0	0	1	0	1	0	0	0	1
GHG (CO ₂ e) ¹	36,741	1,629	1,435	76	39,881	39,202	2,165	41,367	81,248
HAPs	0.16	0.01	0.004	0.0002	0.17	0.15	0.01	0.16	0.33

Notes:
1. Annual emissions of GHG are given in metric tons (tonnes) per year.

MEC-4 PROPOSED OPERATION OF ONE SHIP IN STATE WATERS



MEC-5 PROPOSED OPERATION OF TWO SHIPS NEAR BERTH (MODELING SCENARIOS)



WORST CASE EMISSION RATES WHILE AT BERTH (2 Ship Modeling Summary)

Tug size and usage assumed the same for LNGc with IC engine or LNGc with steam engine.
All maneuvering operations (including LNGc) considered intermittent. Emissions annualized for 1-hour NO₂/SO₂ modeling.

Source	Task	Emission Rates (g/s)																
		NO2							CO		SO2				PM2.5		PM10	
		1-hour -1-	1-hour -2-	1-hour -3-	1-hour -4-	1-hour -5-	24-hour	Annual	1-hour -1-	8-hour	1-hour -4-	3-hour	24-hour	Annual	24-hour	Annual	24-hour	Annual
South Carrier	LNGc 1 Maneuvering IN							1.30E-01						4.44E-04		4.21E-03		4.70E-03
	LNGc 1 Cool Down							1.50E-01						1.06E-03		5.77E-03		6.38E-03
	LNGc 1 Loading	5.29	5.29	5.29			3.9667	1.10E+00	6.94	6.94			0.68	4.14E-03	0.1859	4.16E-02	0.2107	4.60E-02
	LNGc 1 Hoteling							4.23E-01						3.91E-03		1.64E-02		1.81E-02
	LNGc 1 Purge Lines				3.08		0.450	1.09E-01			0.90	0.90	0.13	7.70E-04	0.036	4.18E-03	0.041	4.62E-03
	LNGc 1 Maneuvering OUT					0.132	0.473	1.30E-01					0.06	4.44E-04	0.016	4.21E-03	0.018	4.70E-03
North Carrier	LNGc 2 Maneuvering IN	0.132					0.473	1.30E-01	12.69	12.69			0.06	4.44E-04	0.016	4.21E-03	0.018	4.70E-03
	LNGc 2 Cool Down		3.08				0.450	1.50E-01					0.13	1.06E-03	0.036	5.77E-03	0.041	6.38E-03
	LNGc 2 Loading				5.29	5.29	1.322	1.10E+00			0.90	0.90	0.23	4.14E-03	0.062	4.16E-02	0.070	4.60E-02
	LNGc 2 Hoteling			3.08			1.734	4.23E-01					0.51	3.91E-03	0.139	1.64E-02	0.158	1.81E-02
	LNGc 2 Purge Lines							1.09E-01						7.70E-04		4.18E-03		4.62E-03
	LNGc 2 Maneuvering OUT							1.30E-01						4.44E-04		4.21E-03		4.70E-03
Support Tugs	Tug 1 Maneuver IN	0.042					0.076	4.24E-02	5.071	5.071			0.000	3.06E-05	0.003	1.41E-03	0.003	1.41E-03
	Tug 2 Maneuver IN	0.042					0.076	4.24E-02	5.071	5.071			0.000	3.06E-05	0.003	1.41E-03	0.003	1.41E-03
	Tug 3 Maneuver IN	0.042					0.076	4.24E-02	5.071	5.071			0.000	3.06E-05	0.003	1.41E-03	0.003	1.41E-03
	Tug 4 Maneuver IN	0.042					0.076	4.24E-02	5.071	5.071			0.000	3.06E-05	0.003	1.41E-03	0.003	1.41E-03
	Tug 1 Maneuver LNG Carrier Guard/Ice Clearing**		1.825	1.825	1.825		1.673	1.10E+00			0.001	0.001	0.001	7.93E-04	0.056	3.66E-02	0.056	3.66E-02
	Tug 2 Maneuver LNG Carrier Guard/Ice Clearing**		1.825	1.825	1.825		1.673	6.35E-01			0.001	0.001	0.001	4.61E-04	0.056	2.16E-02	0.056	2.16E-02
	Tug 1 Maneuver OUT					0.042	0.076	4.24E-02					0.000	3.06E-05	0.003	1.41E-03	0.003	1.41E-03
	Tug 2 Maneuver OUT					0.042	0.076	4.24E-02					0.000	3.06E-05	0.003	1.41E-03	0.003	1.41E-03
	Tug 3 Maneuver OUT					0.042	0.076	4.24E-02					0.000	3.06E-05	0.003	1.41E-03	0.003	1.41E-03
	Tug 4 Maneuver OUT					0.042	0.076	4.24E-02					0.000	3.06E-05	0.003	1.41E-03	0.003	1.41E-03
TOTAL		5.59	12.02	12.02	12.02	5.59	12.82	6.15	39.91	39.91	1.81	1.81	1.80	0.02	0.62	0.22	0.69	0.24

Annualized Emissions	1 hr	204 calls/year

**** Emissions distributed over 5 point sources**

Source	Modeled Emission Rate (g/s)																	
	NO2						CO		SO2				PM2.5		PM10			
	1-hour					24-hour	Annual	1-hour	8-hour	1-hour	3-hour	24-hour	Annual	24-hour	Annual	24-hour	Annual	
LNGCAR1 (South Carrier)	5.29E+00	5.29E+00	5.29E+00	3.08E+00	1.32E-01	4.89E+00	2.04E+00	6.94E+00	6.94E+00	9.03E-01	9.03E-01	8.70E-01	1.08E-02	2.38E-01	7.63E-02	2.70E-01	8.45E-02	
LNGCAR2 (North Carrier)	1.32E-01	3.08E+00	3.08E+00	5.29E+00	5.29E+00	3.98E+00	2.04E+00	1.27E+01	1.27E+01	9.03E-01	9.03E-01	9.26E-01	1.08E-02	2.54E-01	7.63E-02	2.87E-01	8.45E-02	
TG_MAN1S Maneuvering (with S Carrier)					4.24E-02	7.61E-02	4.24E-02	0.00E+00				5.49E-05	3.06E-05	2.54E-03	1.41E-03	2.54E-03	1.41E-03	
TG_MAN2S Maneuvering (with S Carrier)					4.24E-02	7.61E-02	4.24E-02	0.00E+00				5.49E-05	3.06E-05	2.54E-03	1.41E-03	2.54E-03	1.41E-03	
TG_MAN3S Maneuvering (with S Carrier)					4.24E-02	7.61E-02	4.24E-02	0.00E+00				5.49E-05	3.06E-05	2.54E-03	1.41E-03	2.54E-03	1.41E-03	
TG_MAN4S Maneuvering (with S Carrier)					4.24E-02	7.61E-02	4.24E-02	0.00E+00				5.49E-05	3.06E-05	2.54E-03	1.41E-03	2.54E-03	1.41E-03	
TG_MAN1N Maneuvering (with N Carrier)	4.24E-02					7.61E-02	4.24E-02	5.07E+00	5.07E+00				5.49E-05	3.06E-05	2.54E-03	1.41E-03	2.54E-03	1.41E-03
TG_MAN2N Maneuvering (with N Carrier)	4.24E-02					7.61E-02	4.24E-02	5.07E+00	5.07E+00				5.49E-05	3.06E-05	2.54E-03	1.41E-03	2.54E-03	1.41E-03
TG_MAN3N Maneuvering (with N Carrier)	4.24E-02					7.61E-02	4.24E-02	5.07E+00	5.07E+00				5.49E-05	3.06E-05	2.54E-03	1.41E-03	2.54E-03	1.41E-03
TG_MAN4N Maneuvering (with N Carrier)	4.24E-02					7.61E-02	4.24E-02	5.07E+00	5.07E+00				5.49E-05	3.06E-05	2.54E-03	1.41E-03	2.54E-03	1.41E-03
TG_ICE1A Guard/Ice Clearing S of berth		3.65E-01	3.65E-01	3.65E-01		3.35E-01	2.20E-01	0.00E+00		2.64E-04	2.64E-04	2.42E-04	1.59E-04	1.12E-02	7.32E-03	1.12E-02	7.32E-03	
TG_ICE1B Guard/Ice Clearing S of berth		3.65E-01	3.65E-01	3.65E-01		3.35E-01	2.20E-01	0.00E+00		2.64E-04	2.64E-04	2.42E-04	1.59E-04	1.12E-02	7.32E-03	1.12E-02	7.32E-03	
TG_ICE1C Guard/Ice Clearing S of berth		3.65E-01	3.65E-01	3.65E-01		3.35E-01	2.20E-01	0.00E+00		2.64E-04	2.64E-04	2.42E-04	1.59E-04	1.12E-02	7.32E-03	1.12E-02	7.32E-03	
TG_ICE1D Guard/Ice Clearing S of berth		3.65E-01	3.65E-01	3.65E-01		3.35E-01	2.20E-01	0.00E+00		2.64E-04	2.64E-04	2.42E-04	1.59E-04	1.12E-02	7.32E-03	1.12E-02	7.32E-03	
TG_ICE1E Guard/Ice Clearing S of berth		3.65E-01	3.65E-01	3.65E-01		3.35E-01	2.20E-01	0.00E+00		2.64E-04	2.64E-04	2.42E-04	1.59E-04	1.12E-02	7.32E-03	1.12E-02	7.32E-03	
TG_ICE2A Guard/Ice Clearing N of berth		3.65E-01	3.65E-01	3.65E-01		3.35E-01	1.27E-01	0.00E+00		2.64E-04	2.64E-04	2.42E-04	9.21E-05	1.12E-02	4.31E-03	1.12E-02	4.31E-03	
TG_ICE2B Guard/Ice Clearing N of berth		3.65E-01	3.65E-01	3.65E-01		3.35E-01	1.27E-01	0.00E+00		2.64E-04	2.64E-04	2.42E-04	9.21E-05	1.12E-02	4.31E-03	1.12E-02	4.31E-03	
TG_ICE2C Guard/Ice Clearing N of berth		3.65E-01	3.65E-01	3.65E-01		3.35E-01	1.27E-01	0.00E+00		2.64E-04	2.64E-04	2.42E-04	9.21E-05	1.12E-02	4.31E-03	1.12E-02	4.31E-03	
TG_ICE2D Guard/Ice Clearing N of berth		3.65E-01	3.65E-01	3.65E-01		3.35E-01	1.27E-01	0.00E+00		2.64E-04	2.64E-04	2.42E-04	9.21E-05	1.12E-02	4.31E-03	1.12E-02	4.31E-03	
TG_ICE2E Guard/Ice Clearing N of berth		3.65E-01	3.65E-01	3.65E-01		3.35E-01	1.27E-01	0.00E+00		2.64E-04	2.64E-04	2.42E-04	9.21E-05	1.12E-02	4.31E-03	1.12E-02	4.31E-03	

WORST CASE EMISSION RATES WHILE AT BERTH (2 Ship Modeling Summary)

Tug size and usaged assumed the same for LNGc with IC
All maneuvering operations (including LNGc) considered intermittent. Emissions annualized for 1-hour NO2/SO2 modeling.

Source	Task	Speciated Emissions						
		Equipment Type	Fuel Type	PMF/SOIL	EC - PM2.5	EC - PM10	SOA - PM2.5	SOA - PM10
				short-term	short-term	short-term	short-term	short-term
South Carrier	LNGc 1 Maneuvering IN	Generator	Diesel					
	LNGc 1 Cool Down	Generator	Diesel					
	LNGc 1 Loading	Generator	Diesel	0.0000	0.1602	0.1824	0.0258	0.0283
	LNGc 1 Hoteling	Generator	Diesel					
	LNGc 1 Purge Lines	Generator	Diesel	0.0000	0.0311	0.0355	0.0050	0.0055
	LNGc 1 Maneuvering OUT	Generator	Diesel	0.0000	0.0138	0.0158	0.0022	0.0024
North Carrier	LNGc 2 Maneuvering IN	Generator	Diesel	0.0000	0.0138	0.0158	0.0022	0.0024
	LNGc 2 Cool Down	Generator	Diesel	0.0000	0.0311	0.0355	0.0050	0.0055
	LNGc 2 Loading	Generator	Diesel	0.0000	0.0534	0.0608	0.0086	0.0094
	LNGc 2 Hoteling	Generator	Diesel	0.0000	0.1201	0.1368	0.0193	0.0212
	LNGc 2 Purge Lines	Generator	Diesel					
	LNGc 2 Maneuvering OUT	Generator	Diesel					
Support Tugs	Tug 1 Maneuver IN	Generator	Diesel	0.0000	0.0022	0.0022	0.0004	0.0003
	Tug 2 Maneuver IN	Generator	Diesel	0.0000	0.0022	0.0022	0.0004	0.0003
	Tug 3 Maneuver IN	Generator	Diesel	0.0000	0.0022	0.0022	0.0004	0.0003
	Tug 4 Maneuver IN	Generator	Diesel	0.0000	0.0022	0.0022	0.0004	0.0003
	Tug 1 Maneuver LNG Carrier Guard/Ice Clearing**	Generator	Diesel	0.0000	0.0481	0.0483	0.0077	0.0075
	Tug 2 Maneuver LNG Carrier Guard/Ice Clearing**	Generator	Diesel	0.0000	0.0481	0.0483	0.0077	0.0075
	Tug 1 Maneuver OUT	Generator	Diesel	0.0000	0.0022	0.0022	0.0004	0.0003
	Tug 2 Maneuver OUT	Generator	Diesel	0.0000	0.0022	0.0022	0.0004	0.0003
	Tug 3 Maneuver OUT	Generator	Diesel	0.0000	0.0022	0.0022	0.0004	0.0003
	Tug 4 Maneuver OUT	Generator	Diesel	0.0000	0.0022	0.0022	0.0004	0.0003
TOTAL				0.00	0.54	0.60	0.09	0.09

Annualized Emissions

** Emissions distributed over 5 point sources

Source	UTM X	UTM Y	lc-x	lc-y	Stack Ht	Exit Temp	Exit Vel	Diam	PMF/SOIL	EC - PM2.5	EC - PM10	SOA - PM2.5	SOA - PM10
	(m)	(m)	km	km	(m)	(K)	(msec)	(m)					
LNGCAR1 (South Carrier)	588362.600	6725207.770	-21.0638	184.0375	45	589	4.2	1.68	0.00E+00	2.05E-01	2.34E-01	3.30E-02	3.63E-02
LNGCAR2 (North Carrier)	588176.020	6725657.540	-21.2378	184.4943	45	589	4.2	1.68	0.00E+00	2.19E-01	2.49E-01	3.51E-02	3.86E-02
TG_MAN1S Maneuvering (with S Carrier)	588332.800	6725273.480	-21.0918	184.1043	10.7	589	23.0	0.46	0.00E+00	2.18E-03	2.19E-03	3.51E-04	3.41E-04
TG_MAN2S Maneuvering (with S Carrier)	588308.660	6725140.990	-21.1199	183.9721	10.7	589	23.0	0.46	0.00E+00	2.18E-03	2.19E-03	3.51E-04	3.41E-04
TG_MAN3S Maneuvering (with S Carrier)	588375.430	6724981.830	-21.0576	183.8104	10.7	589	23.0	0.46	0.00E+00	2.18E-03	2.19E-03	3.51E-04	3.41E-04
TG_MAN4S Maneuvering (with S Carrier)	588499.330	6724892.380	-20.9359	183.7170	10.7	589	23.0	0.46	0.00E+00	2.18E-03	2.19E-03	3.51E-04	3.41E-04
TG_MAN1N Maneuvering (with N Carrier)	588149.500	6725723.230	-21.2624	184.5610	10.7	589	23.0	0.46	0.00E+00	2.18E-03	2.19E-03	3.51E-04	3.41E-04
TG_MAN2N Maneuvering (with N Carrier)	588135.070	6725558.940	-21.2818	184.3966	10.7	589	23.0	0.46	0.00E+00	2.18E-03	2.19E-03	3.51E-04	3.41E-04
TG_MAN3N Maneuvering (with N Carrier)	588189.670	6725428.530	-21.2308	184.2641	10.7	589	23.0	0.46	0.00E+00	2.18E-03	2.19E-03	3.51E-04	3.41E-04
TG_MAN4N Maneuvering (with N Carrier)	588312.470	6725342.390	-21.1101	184.1741	10.7	589	23.0	0.46	0.00E+00	2.18E-03	2.19E-03	3.51E-04	3.41E-04
TG_ICE1A Guard/Ice Clearing S of berth	588643.590	6724743.530	-20.7956	183.5634	10.7	589	23.0	0.46	0.00E+00	9.61E-03	9.66E-03	1.54E-03	1.50E-03
TG_ICE1B Guard/Ice Clearing S of berth	588568.690	6724698.670	-20.8720	183.5206	10.7	589	23.0	0.46	0.00E+00	9.61E-03	9.66E-03	1.54E-03	1.50E-03
TG_ICE1C Guard/Ice Clearing S of berth	588468.250	6724675.720	-20.9735	183.5006	10.7	589	23.0	0.46	0.00E+00	9.61E-03	9.66E-03	1.54E-03	1.50E-03
TG_ICE1D Guard/Ice Clearing S of berth	588342.990	6724702.320	-21.0984	183.5309	10.7	589	23.0	0.46	0.00E+00	9.61E-03	9.66E-03	1.54E-03	1.50E-03
TG_ICE1E Guard/Ice Clearing S of berth	588264.510	6724768.630	-21.1752	183.5998	10.7	589	23.0	0.46	0.00E+00	9.61E-03	9.66E-03	1.54E-03	1.50E-03
TG_ICE2A Guard/Ice Clearing N of berth	588166.430	6725931.300	-21.2393	184.7693	10.7	589	23.0	0.46	0.00E+00	9.61E-03	9.66E-03	1.54E-03	1.50E-03
TG_ICE2B Guard/Ice Clearing N of berth	588038.920	6725895.240	-21.3683	184.7369	10.7	589	23.0	0.46	0.00E+00	9.61E-03	9.66E-03	1.54E-03	1.50E-03
TG_ICE2C Guard/Ice Clearing N of berth	587964.450	6725845.460	-21.4445	184.6891	10.7	589	23.0	0.46	0.00E+00	9.61E-03	9.66E-03	1.54E-03	1.50E-03
TG_ICE2D Guard/Ice Clearing N of berth	587909.780	6725743.460	-21.5024	184.5884	10.7	589	23.0	0.46	0.00E+00	9.61E-03	9.66E-03	1.54E-03	1.50E-03
TG_ICE2E Guard/Ice Clearing N of berth	587890.310	6725642.710	-21.5249	184.4879	10.7	589	23.0	0.46	0.00E+00	9.61E-03	9.66E-03	1.54E-03	1.50E-03

MEC-7

MARINE EMISSIONS ASSUMPTIONS

Vessel Fleeting Assumptions

- 1 The vessels coming into port at the LNG facility are assumed to be a mixture of purpose built vessels and vessels of opportunity
- It is assumed that all vessels are newer than 2013
- All purpose built vessels are assumed to be Category 3 Tier 3 for the Main Propulsion Engines and Tier 4 or Tier 3 for the Auxiliary Engines (either Cat 2 or 3)
- Tier 4 was not assumed for the Category 2 engines to be conservative with the emissions factor estimates (All Tier 4 Category 2 Engines to have NOx emission factor of 1.8 g/kW-hr)
- It is assumed that the purpose built main propulsion engines will have the capacity to be dual fuel engines and utilize the boiled off LNG gas during manuevering in and out of the terminal.

Vessels	%
Purpose Built	80
Vessels of Opp	20

- 2 Fleeting assumptions based on the projected 2025 fleet mix
- 3 SO2 liquid fuel emissions from IFC Ports Inventory Document from Table 2-9 for SSD/MDO for the Category 3 Main engines divided by 667 for 15 ppm sulfur content based on Ultra Low Sulfur Diesel (ULSD) sulfur
- 4 SO2 for liquid fuel emissions from IFC Ports Inventory Table 3-8 for Tier 2 Harbor Craft, divided by 1000 based on a 15 ppm sulfur content for Ultra Low Sulfur Diesel (ULSD) sulfur requirements
- 5 Assume fleet will be under the MARPOL PROTOCOL the 40 CFR 1043.6 sulfur limit of 0.1% for all ECA and ECA associated area after year 2020, fuel assumed to be ULSD near terminal
- ECA Associated area available at: http://www.imo.org/blast/blastDataHelper.asp?data_id=28815&filename=190%2860%29.pdf

Emission Factors Assumptions

- 1 PM2.5 assumed to be 97% of PM10 for marine diesel firing. PM2.5 assumed to be 100% of PM10 for NG firing.

Natural Gas Emission Factors Notes (Spark Ignition):

- 1a Emission Factor for NOx based on 40 CFR 1045 Subpart B conventional inboard engines
- 2a Per the California South Coast Air Quality Management District off-road engine tables and Carl Moyer Program Guidelines, appropriate
- NOx & NMHC fractions are 95% and 5%, respectively. Same ratio used by Golden Pass for tugboat Tier II emissions (No. 2 fuel oil)
- 3a PM10 and PM2.5 emission factors from AP42 Table 3.2-3 Uncontrolled Emission Factors from 4-Stroke Rich-Burn Engines. Includes filterable and condensable
- 4a CO2e emissions from 40 CFR 98 Subpart C: Table C-1: Default CO2 Emission Factors and High Heat Values for Various Types of Fuel and C-2: Default CH4 and N2O Emission Factors for Various Types of Fuel
- 5a To determine CO2e emissions in terms of g/kWh for the Natural Gas emissions, a specific brake fuel consumption was assumed. This value was assumed from Table 2-2: Brake Specific Fuel Consumption for Compressor Engines in the Natural Gas Compressor Engine Survey for Gas Production and Processing Facilities (H68 Final Report)
- 9000 btu/hp-hr
- 0.012069 mmbtu/kW-hr

Marine Diesel Emission Factors Notes (Compression Ignition):

- 1b IMO Category 1&2 Tier 1&2 Engine emission factors based on derated speed to add conservatism to the NOx emission factor based on 40 CFR 1042 Subpart J; Cat 1&2 Tier 1 did not have any emission regulations for VOC, emissions are assumed as largest Tier 2 VOC possibility
- 2b IMO Category 1&2 Tier 3 and 4 Engine emission factors based on derated speed to add conservatism to the NOx emission factor based on 40 CFR 1042 Subpart B
- 3b IMO Category 3 Engine emission factors based on derated speed to add conservatism to the NOx emission factor based on 40 CFR 1042 Subpart B; Tier 1 Category 3 CO and VOC Emissions were not regulated, Tier 1 emissions assumed equal to Tier 2
- 4b Per the California South Coast Air Quality Management District off-road engine tables and Carl Moyer Program Guidelines, appropriate
- NOx & NMHC fractions are 95% and 5%, respectively. Same ratio used by Golden Pass for tugboat Tier II emissions (No. 2 fuel oil)
- 5b Liquid Fuel: CH4 and NO2 emissions from Port Inventory Emissions Document Table 2-13: Greenhouse Gas Emission Factors, g/kWh. Using MDO or MGO fuel with SSD propulsion, all 3 GHG emissions added together for 1 emission factor
- 6b Liquid Fuel: CO2 emissions from Port Inventory Emissions Document Table 2-9: Emission Factors for OGV Main Engines, g/kWh (for Category 3) and Table 3-8: Harbor Craft Emission Factors, g/kWh (for Category 1 and 2). Using MDO or MGO fuel with SSD propulsion, all 3 GHG emissions added together for 1 emission factor
- 7b PM10, and PM2.5 liquid fuel emissions from IFC Ports Inventory Document from Table 2-9 for SSD/MGO (main engines) and MSD/MGO (auxiliary engines) to match sulfur content of 0.1%

Combustion Engine Assumptions

- 1 Ship data originates from the Q-Max Vessel Information (Propulsion Trends in LNG Carriers MAN Diesel)
- 2 Loading rate based on a 12,500 m3/hr (individual calculations based on 1 ship and 1 call) provided by Megan Evans on May 19th
- 3 Hoteling load is assumed to be 20% of auxiliary engines, does not include loading pump operation.
- 4 Low Load Adjustment factors have been applied to any operation of the main propulsion engines below a 20% load factor
- 5 Assumes the use of an Economizer and a constant outlet exhaust temperature of 600°F

Steam Engine Assumptions

- 1 Ship data originates from the Q-Flex Vessel Information (Propulsion Trends in LNG Carriers MAN Diesel) - Assumed to be same vessel used with Steam Turbine Propulsion
- 2 Loading rate based on a 12,500 m3/hr (from only one berth at a time) provided by Megan Evans on Feb 21, 2013 at 10:32 am
- 3 Assumed total output power onboard of 37,000 kW from Steam Turbine and Auxiliary Turbo Generators
- 4 Number of operating boilers/turbines/generators taken into account with overall onboard power load factor.
- 5 Hoteling load is assumed to be 5,000 kW for all berth related operations, based on maximum outlet power from the assumed auxiliary engine
- 6 Emissions rates based on ST engine type, using MDO fuel in Port-Related Emissions Inventories: Ocean Going Vessels: Table 2-9: Emission Factors for OGV Main Engines, g/kWh, page 2-18
- 7 LNG Carrier Main Engine VOC emissions represented by HC emissions rate located in Port-Related Emissions Inventories: Ocean Going Vessels: Table 2-9: Emission Factors for OGV Main Engines, g/kWh, page 2-14
- 8 SO2, PM10, and PM2.5 emissions from IFC Ports Inventory Document from Table 2-9 for ST/MGO for 0.1% sulfur content based on MARPOL 2020 sulfur requirements
- 9 Assumes the use of an Economizer and a constant outlet exhaust temperature of 600°F

Tug Assumptions

- 1 Tug Data from Alexsandr Iyerusalimskiy Email: LNG Carriers Operation and Description for Final Air Modeling (June 17, 2016)
- 2 Assumes the use of an Economizer, with a constant outlet exhaust temperature of 600°F during maneuvering operations. The exhaust temperature of 450°F is used during idling
- 3 90-ton Tug engine information used with additional 22% (110/90) margin added to account for possibility of 110-ton Tugs used. 110-ton tug info not available
- 4 Ice Management season is assumed to occur December 1st through May 31st (Total 181 days). Ice Management Season requires 1 additional tug to be operating while a Carrier is at berth to break up the ice

Engine Type Assumptions

Main Propulsion Combustion Engine	Main Propulsion Steam Turbine	Reference
Twin Screw, Twin Engine, Two Stroke Low Speed 91 rpm max. 2 x 17,978kW (MCR) MAN 7S70MC-C, or equal Specific fuel Consumption = 169g/kWh @ fuel calorific value 42,700kJ/kg Fuel Type: Residual Oil, 2.7% Sulfur 700mm Bore x 2,800mm S EPA Category 3	Single Screw, Steam Turbine Kawasaki UA-400 Cross Compound Impulse Turbine, 28,000kW at 83 rpm MCR. 25,200kW at 80rpm NCR. Main Boilers (2) - Mitsubishi MB-4E Marine Boiler with oil and gas combination burners. Vertical Two Drum Water Tube. Max. Evaporation 65,000kg/hour each. Assumed Latent Heat of Vaporization of water = 2260 kJ/kg Fuel Type: Residual Oil, 2.7% Sulfur	 Combustion Engine: From Compass Port Main Propulsion Diesel Engine Only Steam Engine: From Compass Port Main Propulsion Steam Engine Only
Auxiliary Combustion Engine	Auxiliary Steam Engine	Reference
3,150kW CAT 3612 Marine Generator Set, or equal Specific fuel Consumption = 191.4g/kWh @ fuel calorific value 42,700kJ/kg Fuel Type: Residual Oil, 2.7% Sulfur 280mm Bore x 300mm Stroke = 18.5dm3 / cylinder EPA Category 2	2 x Mitsubishi Multi-Stage Condensing Turbine Generators Generator rated output = 3,150kW at 1800rpm 1 x 3,330kW Wartsila VASA 9R32LND, 4-Stroke, Turbo-charged, Intercooled Diesel Generator, 720rpm	Combustion Engine Category 2: From Compass Port Auxiliary Diesel Engine Only
4-Stroke, 9-Cylinder Man Diesel, MAN 9L35/44DF Engine Output: 4,770 kW, Rated Speed: 750 RPM. Dual Fuel. Engine Heat Rate: 7,530 kJ/kWh EPA Category 3		Combustion Engine Category 3: From AECOM Tier III LNG Carrier Hoteling Emissions Calculation, 4-6-2015 Steam Engine: From Compass Port Power Generation Steam Engine Only
90-Ton Tug Combustion Engine		Reference
4-Stroke Diesel Engine 3516C Tier 4 2 x 1500kW (Vendor sheet provided 1590-1995 bkW) WITH 22% ADDITIONAL MARGIN 2 x 2433.9 bkW Fuel Type: MGO/DMA 170mm Bore x 215mm Stroke = 69 L / cylinder (Too Large) EPA Category 2		90-Ton Tug: Jim Pfeiffer Email, Subject: Tug Info-More Details Necessary? Referenced Nichols Bros Boat Builders website, Hull # S-169 M/V Delta Audrey

MEC-8 LOW LOAD ADJUSTMENT FACTOR

FACTORS TO ADJUST G/KW-HR EMISSION FACTOR AT LOW LOAD CONDITIONS

Reference Table 2-15: Calculated Low Load Multiplicative Adjustment Factor from Port-Related Emissions Inventories

Load	NOx	HC	CO	PM	SO ₂	CO ₂
1%	11.47	59.28	19.32	19.17	5.99	5.82
2%	4.63	21.18	9.68	7.29	3.36	3.28
3%	2.92	11.68	6.46	4.33	2.49	2.44
4%	2.21	7.71	4.86	3.09	2.05	2.01
5%	1.83	5.61	3.89	2.44	1.79	1.76
6%	1.60	4.35	3.25	2.04	1.61	1.59
7%	1.45	3.52	2.79	1.79	1.49	1.47
8%	1.35	2.95	2.45	1.61	1.39	1.38
9%	1.27	2.52	2.18	1.48	1.32	1.31
10%	1.22	2.20	1.96	1.38	1.26	1.25
11%	1.17	1.96	1.79	1.30	1.21	1.21
12%	1.14	1.76	1.64	1.24	1.18	1.17
13%	1.11	1.60	1.52	1.19	1.14	1.14
14%	1.08	1.47	1.41	1.15	1.11	1.11
15%	1.06	1.36	1.32	1.11	1.09	1.08
16%	1.05	1.26	1.24	1.08	1.07	1.06
17%	1.03	1.18	1.17	1.06	1.05	1.04
18%	1.02	1.11	1.11	1.04	1.03	1.03
19%	1.01	1.05	1.05	1.02	1.01	1.01
20%	1.00	1.00	1.00	1.00	1.00	1.00

PUBLIC

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MEC-9 INTERNAL COMBUSTION ENGINE FLEETING

2025 FLEETING MIX

Vessel arrival determined below for projected 2025 fleet mix, include both purpose built vessels (80%) and vessels of opportunity (20%). This mix assumes two engine types, spark ignition or compression ignition. The fleet weighting factors are then used to determine an average emission factor based on engine type occurrence at port. The fleet-weighted average emission factors are then used to determine carrier/call specific emissions for the combustion (non-steam turbine) engines.

* Category 3 Engines different for Main Propulsion Engines from Auxiliary Engines, see IC Engine Category for difference in size

MAIN PROPULSION ENGINES

			Assumed (Engine-Specific) Emission Factor									Fleet-Weighted Average Emission Factor							
Engine Type	Engine Category	Standard	NOx	CO	SOx	VOC	PM2.5	PM10	GHG (CO2E)	HAPs	Fleet Weighting Factor	Hybrid NOx (g/k W-hr)	Hybrid CO (g/k W-hr)	Hybrid SOx (g/k W-hr)	Hybrid VOC (g/k W-hr)	Hybrid PM2.5 (g/k W-hr)	Hybrid PM10 (g/k W-hr)	Hybrid GHG (CO2E) (g/k W-hr)	Hybrid HAPs (g/k W-hr)
Spark Ignition	n/a	NG	4.75	75.00	0.000	0.25	0.11	0.11	640.45	0.123	0%	0	0	0	0	0	0	0	0
Compression Ignition	Category 1	Tier 1	13.42	5.00	0.005	1.00	0.78	0.80	699.39	0.006	0%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Tier 2	6.84	5.00	0.005	0.36	0.58	0.60	699.39	0.006	0%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Tier 3	5.51	5.00	0.005	0.29	0.11	0.11	699.39	0.006	0%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Category 2	Tier 1	10.63	5.00	0.005	1.00	0.49	0.50	699.39	0.003	0%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Tier 2	7.41	5.00	0.005	0.39	0.49	0.50	699.39	0.003	0%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Tier 3	7.41	5.00	0.005	0.39	0.14	0.14	699.39	0.003	0%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Tier 4	1.80	5.00	0.005	0.19	0.06	0.06	699.39	0.003	0%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Category 3*	Tier 1	18.51	5.00	0.005	2.00	0.17	0.19	598.18	0.003	0%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Tier 2	15.84	5.00	0.005	2.00	0.17	0.19	598.18	0.003	20%	3.17	1.00	0.00	0.40	0.03	0.04	119.64	0.00
		Tier 3	3.40	5.00	0.005	2.00	0.17	0.19	598.18	0.003	80%	2.72	4.00	0.00	1.60	0.14	0.15	478.54	0.00
Total											100%	5.89	5.00	0.01	2.00	0.17	0.19	598.18	0.00

AUXILIARY ENGINES

			Assumed (Engine-Specific) Emission Factor									Fleet-Weighted Average Emission Factor								
Engine Type	Engine Category	Standard	NOx	CO	SOx	VOC	PM2.5	PM10	GHG (CO2E)	HAPs	Fleet Weighting Factor	Hybrid NOx (g/k W-hr)	Hybrid CO (g/k W-hr)	Hybrid SOx (g/k W-hr)	Hybrid VOC (g/k W-hr)	Hybrid PM2.5 (g/k W-hr)	Hybrid PM10 (g/k W-hr)	Hybrid GHG (CO2E) (g/k W-hr)	Hybrid HAPs (g/k W-hr)	
Spark Ignition	n/a	NG	4.75	75.00	0.000	0.25	0.11	0.11	640.45	0.123	0%	0	0	0	0	0	0	0	0	
Compression Ignition	Category 1	Tier 1	13.42	5.00	0.001	1.00	0.78	0.80	699.39	0.006	0%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
		Tier 2	6.84	5.00	0.001	0.36	0.58	0.60	699.39	0.006	0%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
		Tier 3	5.51	5.00	0.001	0.29	0.11	0.11	699.39	0.006	0%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	Category 2	Tier 1	10.63	5.00	0.001	1.00	0.49	0.50	699.39	0.003	0%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
		Tier 2	7.41	5.00	0.001	0.39	0.49	0.50	699.39	0.003	0%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
		Tier 3	7.41	5.00	0.001	0.39	0.14	0.14	699.39	0.003	0%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
		Tier 4	1.80	5.00	0.001	0.19	0.06	0.06	699.39	0.003	25%	0.45	1.25	0.00	0.05	0.02	0.02	174.85	0.00	
	Category 3*	Tier 1	12.37	5.00	0.001	2.00	0.17	0.19	655.47	0.003	0%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
		Tier 2	9.97	5.00	0.001	2.00	0.17	0.19	655.47	0.003	20%	1.99	1.00	0.00	0.40	0.03	0.04	131.09	0.00	
		Tier 3	2.48	5.00	0.001	2.00	0.17	0.19	655.47	0.003	55%	1.36	2.75	0.00	1.10	0.09	0.10	360.51	0.00	
											Total	100%	3.81	5.00	0.00	1.55	0.14	0.16	666.45	0.00

MEC-10 INTERNAL COMBUSTION ENGINE CATEGORY

NEEDED FOR TIER I & II
NEEDED FOR TIER I

	CAT 1 ENGINE	CAT 2 ENGINE	CAT 3 ENGINE (AUXILIARY)	CAT 3 ENGINE (MAIN)	
Typical Engine Model		3516C	MAN 9L35/44DF	MAN 7S70MC-C	
Engine Type		4-Stroke	4-Stroke	4-Stroke	
Rated Speed	500	1600	750	100	rpm
85% Derated Speed	425	1360	638	85	rpm
Engine Output	200	3,150	4700.0	16,700	kW
Displacement	5.0	10.0	n/a	n/a	L/cyl
Power Density	40.0	n/a	n/a	n/a	kW/L

See Assumptions for Engine Descriptions

MEC-11 INTERNAL COMBUSTION ENGINE EMISSION FACTORS

NOx Emission Factors:

Fuel	Natural Gas		Marine Diesel							
Engine Category	n/a		IMO Category 1		IMO Category 2		IMO Category 3 (Auxiliary)		IMO Category 3 (Main)	
Emission Factor Units	(g/kW-hr)	(g/kW-hr)	(g/kW-hr)	(g/kW-hr)	(g/kW-hr)	(g/kW-hr)	(g/kW-hr)	(g/kW-hr)	(g/kW-hr)	(g/kW-hr)
Spark Ignition (1a, 2a)	4.75	4.75								
Compression Ignition - Tier 1 (1b, 3b, 4b)			13.42	13.4	10.63	10.6	12.37	12.4	18.51	18.5
Compression Ignition - Tier 2 (1b, 3b, 4b)			6.84	6.8	7.41	7.4	9.97	10.0	15.84	15.8
Compression Ignition - Tier 3 (1b, 3b, 4b)			5.51	5.5	7.41	7.4	2.48	2.5	3.40	3.4
Compression Ignition - Tier 4 (2b)					1.800	1.8				

CO Emission Factors:

Fuel	Natural Gas		Marine Diesel							
Engine Category	n/a		IMO Category 1		IMO Category 2		IMO Category 3 (Auxiliary)		IMO Category 3 (Main)	
Emission Factor Units	(g/kW-hr)	(g/kW-hr)	(g/kW-hr)	(g/kW-hr)	(g/kW-hr)	(g/kW-hr)	(g/kW-hr)	(g/kW-hr)	(g/kW-hr)	(g/kW-hr)
Spark Ignition (1a, 2a)	75.00	75.00								
Compression Ignition - Tier 1 (1b, 3b, 4b)			5.00	5.0	5.00	5.0	5.00	5.0	5.00	5.0
Compression Ignition - Tier 2 (1b, 3b, 4b)			5.00	5.0	5.00	5.0	5.00	5.0	5.00	5.0
Compression Ignition - Tier 3 (1b, 3b, 4b)			5.00	5.0	5.00	5.0	5.00	5.0	5.00	5.0
Compression Ignition - Tier 4 (2b)					5.000	5.0				

VOC Emission Factors:

Fuel	Natural Gas		Marine Diesel							
Engine Category	n/a		IMO Category 1		IMO Category 2		IMO Category 3 (Auxiliary)		IMO Category 3 (Main)	
Emission Factor Units	(g/kW-hr)	(g/kW-hr)	(g/kW-hr)	(g/kW-hr)	(g/kW-hr)	(g/kW-hr)	(g/kW-hr)	(g/kW-hr)	(g/kW-hr)	(g/kW-hr)
Spark Ignition (1a, 2a)	0.25	0.25								
Compression Ignition - Tier 1 (1b, 3b, 4b)			1.00	1.0	1.00	1.0	2.00	2.0	2.00	2.0
Compression Ignition - Tier 2 (1b, 3b, 4b)			0.36	0.4	0.39	0.4	2.00	2.0	2.00	2.0
Compression Ignition - Tier 3 (1b, 3b, 4b)			0.29	0.3	0.39	0.4	2.00	2.0	2.00	2.0
Compression Ignition - Tier 4 (2b)					0.190	0.2				

PM2.5 Emission Factors:

Fuel	Natural Gas		Marine Diesel							
Engine Category	n/a		IMO Category 1		IMO Category 2		IMO Category 3 (Auxiliary)		IMO Category 3 (Main)	
Emission Factor Units	lb PMtotal/mm btu Fuel	(g/kW-hr)	(g/kW-hr)	(g/kW-hr)	(g/kW-hr)	(g/kW-hr)	(g/kW-hr)	(g/kW-hr)	(g/kW-hr)	(g/kW-hr)
Spark Ignition (3a)	0.02	0.11								
Compression Ignition - Tier 1 (1b, 7b)			0.78	0.8	0.49	0.5	0.17	0.2	0.17	0.2
Compression Ignition - Tier 2 (1b, 7b)			0.58	0.6	0.49	0.5	0.17	0.2	0.17	0.2
Compression Ignition - Tier 3 (1b, 2b, 7b)			0.11	0.1	0.14	0.1	0.17	0.2	0.17	0.2
Compression Ignition - Tier 4 (2b)					0.060	0.1				

PM10 Emission Factors:

Fuel	Natural Gas		Marine Diesel							
Engine Category	n/a		IMO Category 1		IMO Category 2		IMO Category 3 (Auxiliary)		IMO Category 3 (Main)	
Emission Factor Units	lb PMtotal/mm btu Fuel	(g/kW-hr)	(g/kW-hr)	(g/kW-hr)	(g/kW-hr)	(g/kW-hr)	(g/kW-hr)	(g/kW-hr)	(g/kW-hr)	(g/kW-hr)
Spark Ignition (3a)	0.02	0.11								
Compression Ignition - Tier 1 (1b, 7b)			0.80	0.8	0.50	0.5	0.19	0.2	0.19	0.2
Compression Ignition - Tier 2 (1b, 7b)			0.60	0.6	0.50	0.5	0.19	0.2	0.19	0.2
Compression Ignition - Tier 3 (1b, 2b, 7b)			0.11	0.1	0.14	0.1	0.19	0.2	0.19	0.2
Compression Ignition - Tier 4 (2b)					0.060	0.1				

CO2 Emission Factors:

Fuel	Natural Gas		Marine Diesel							
Engine Category	n/a		IMO Category 1		IMO Category 2		IMO Category 3 (Auxiliary)		IMO Category 3 (Main)	
Emission Factor Units	kg CO2/mmbtu Fuel	(g/kW-hr)	(g/kW-hr)	(g/kW-hr)	(g/kW-hr)	(g/kW-hr)	(g/kW-hr)	(g/kW-hr)	(g/kW-hr)	(g/kW-hr)
Spark Ignition (4a, 5a)	53.06	640.39								
Compression Ignition - Tier 1 (6b)			690.00	690.0	690.00	690.0	646.08	646.1	588.79	588.8
Compression Ignition - Tier 2 (6b)			690.00	690.0	690.00	690.0	646.08	646.1	588.79	588.8
Compression Ignition - Tier 3 (6b)			690.00	690.0	690.00	690.0	646.08	646.1	588.79	588.8
Compression Ignition - Tier 4 (6b)					690.00	690.0				

CH4 Emission Factors:

Fuel	Natural Gas		Marine Diesel							
Engine Category	n/a		IMO Category 1		IMO Category 2		IMO Category 3 (Auxiliary)		IMO Category 3 (Main)	
Emission Factor Units	kg CH4/mmbtu Fuel	(g/kW-hr)	(g/kW-hr)	(g/kW-hr)	(g/kW-hr)	(g/kW-hr)	(g/kW-hr)	(g/kW-hr)	(g/kW-hr)	(g/kW-hr)
Spark Ignition (4a, 5a)	0.001	0.01								
Compression Ignition - Tier 1 (5b)			0.006	0.0	0.006	0.0	0.006	0.0	0.006	0.0
Compression Ignition - Tier 2 (5b)			0.006	0.0	0.006	0.0	0.006	0.0	0.006	0.0
Compression Ignition - Tier 3 (5b)			0.006	0.0	0.006	0.0	0.006	0.0	0.006	0.0
Compression Ignition - Tier 4 (5b)					0.006	0.0				

N2O Emission Factors:

Fuel	Natural Gas		Marine Diesel							
Engine Category	n/a		IMO Category 1		IMO Category 2		IMO Category 3 (Auxiliary)		IMO Category 3 (Main)	
Emission Factor Units	kg N2O/mmbtu Fuel	(g/kW-hr)	(g/kW-hr)	(g/kW-hr)	(g/kW-hr)	(g/kW-hr)	(g/kW-hr)	(g/kW-hr)	(g/kW-hr)	(g/kW-hr)
Spark Ignition (4a, 5a)	0.0001	0.0012								
Compression Ignition - Tier 1 (5b)			0.031	0.0	0.031	0.0	0.031	0.0	0.031	0.0
Compression Ignition - Tier 2 (5b)			0.031	0.0	0.031	0.0	0.031	0.0	0.031	0.0
Compression Ignition - Tier 3 (5b)			0.031	0.0	0.031	0.0	0.031	0.0	0.031	0.0
Compression Ignition - Tier 4 (5b)					0.031	0.0				

HAPs Emission Factors:

Fuel	Natural Gas		Marine Diesel							
Engine Category	n/a		IMO Category 1		IMO Category 2		IMO Category 3 (Auxiliary)		IMO Category 3 (Main)	
Emission Factor Units	(g/kW-hr)	(g/kW-hr)	(g/kW-hr)	(g/kW-hr)	(g/kW-hr)	(g/kW-hr)	(g/kW-hr)	(g/kW-hr)	(g/kW-hr)	(g/kW-hr)
Spark Ignition	0.123	0.12								
Compression Ignition - Tier 1			0.006	0.0	0.003	0.0	0.003	0.0	0.003	0.0
Compression Ignition - Tier 2			0.006	0.0	0.003	0.0	0.003	0.0	0.003	0.0
Compression Ignition - Tier 3			0.006	0.0	0.003	0.0	0.003	0.0	0.003	0.0
Compression Ignition - Tier 4 (2b)					0.003	0.0				

MEC-12 MAIN ENGINE – INTERNAL COMBUSTION – NORMAL ARRIVAL

Calls Per Year 193.45

Mode	Number of Engines	Power (kW) per Engine	Total Power (kW)		Load Factor	Utilized Power (kW)	Time in Mode (hr)	NOx				CO				SOx				VOC				PM2.5				PM10				GHG (CO2E)				HAPs			
								Factor (g/kW-hr)	Mass Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)
Cruising IN	2	16,700	33,400	Main Engines	80.0%	26,720	0.8	5.89	117,996			5.00	100,200			0.01	109			2.00	40,080			0.17	3,407			0.19	3,808			598.18	11,987,487			0.003	56		
	3	3,150	9,450	Diesel Generators	80.0%	7,560		3.81	21,591			5.00	28,350			0.00	7			1.55	8,774			0.14	808			0.16	893			666.45	3,778,760			0.003	16		
				Total					139,587	410	51.70		128,550	378	47.61		116	0	0.04		48,854	144	18.09		4,215	12	1.56		4,701	14	1.74		15,766,247	46,344	5,839.35		71	0.21	0.03
Approach IN	2	16,700	33,400	Main Engines	25.0%	8,350	2.0	5.89	98,330			5.00	83,500			0.01	91			2.00	33,400			0.17	2,839			0.19	3,173			598.18	9,989,573			0.003	46		
	1	3,150	3,150	Diesel Generators	80.0%	2,520		3.81	19,192			5.00	25,200			0.00	7			1.55	7,799			0.14	718			0.16	794			666.45	3,358,898			0.003	14		
				Total					117,522	130	16.32		108,700	120	15.10		97	0	0.01		41,199	45	5.72		3,557	4	0.49		3,967	4	0.55		13,348,471	14,714	1,853.95		60	0.07	0.01
Far-Terminal Op.: Maneuvering IN	2	16,700	33,400	Main Engines	15.0%	5,010	1.0	6.24	31,269			6.60	33,066			0.01	30			2.64	13,226			0.19	945			0.21	1,057			646.03	3,236,622			0.003	14		
	1	3,150	3,150	Diesel Generators	80.0%	2,520		3.81	9,596			5.00	12,600			0.00	3			1.55	3,900			0.14	359			0.16	397			666.45	1,679,449			0.003	7		
				Total					40,865	90	11.35		45,666	101	12.69		33	0	0.01		17,126	38	4.76		1,304	3	0.36		1,454	3	0.40		4,916,070	10,838	1,365.58		21	0.05	0.01
Near-Terminal Op.: Maneuvering IN	2	16,700	33,400	Main Engines	15.0%	5,010	1.0	6.24	31,269			6.60	33,066			0.01	30			2.64	13,226			0.19	945			0.21	1,057			646.03	3,236,622			0.003	14		
	1	3,150	3,150	Diesel Generators	80.0%	2,520		3.81	9,596			5.00	12,600			0.00	3			1.55	3,900			0.14	359			0.16	397			666.45	1,679,449			0.003	7		
				Total					40,865	90	11.35		45,666	101	12.69		33	0	0.01		17,126	38	4.76		1,304	3	0.36		1,454	3	0.40		4,916,070	10,838	1,365.58		21	0.05	0.01
Cool Down / Vessel Purge	2	16,700	33,400	Main Engines	Shut Down		3.5	5.89	0			5.00	0			0.01	0			2.00	0			0.17	0			0.19	0			598.18	0			0.003	0		
	1	3,150	3,150	Diesel Generators	80.0%	2,520		3.81	33,587			5.00	44,100			0.00	11			1.55	13,649			0.14	1,257			0.16	1,389			666.45	5,878,071			0.003	24		
				Total					33,587	21	2.67		44,100	28	3.50		11	0	0.00		13,649	9	1.08		1,257	1	0.10		1,389	1	0.11		5,878,071	3,702	466.51		24	0.02	0.00
LNG Loading	0	16,700	0	Main Engines	Shut Down		18.00	5.89	0			5.00	0			0.01	0			2.00	0			0.17	0			0.19	0			598.18	0			0.003	0		
	3	3,150	9,450	Diesel Generators	52.9%	5,000		3.81	342,720			5.00	450,000			0.00	117			1.55	139,275			0.14	12,825			0.16	14,175			666.45	59,980,320			0.003	250		
				Total					342,720	42	5.29		450,000	55	6.94		117	0	0.00		139,275	17	2.15		12,825	2	0.198		14,175	2	0.22		59,980,320	7,346	925.62		250	0.03	0.00
Hoteling	0	16,700	0	Main Engines	Shut Down		18.00	5.89	0			5.00	0			0.01	0			2.00	0			0.17	0			0.19	0			598.18	0			0.003	0		
	3	3,150	9,450	Diesel Generators	20.0%	1,890		3.81	129,548			5.00	170,100			0.00	44			1.55	52,646			0.14	4,848			0.16	5,358			666.45	22,672,561			0.003	94		
				Total					129,548	16	2.00		170,100	21	2.63		44	0	0.00		52,646	6	0.81		4,848	1	0.07		5,358	1	0.08		22,672,561	2,777	349.89		94	0.01	0.00
Line Purge/Prep	2	16,700	33,400	Main Engines	Shut Down		3.5	5.89	0			5.00	0			0.01	0			2.00	0			0.17	0			0.19	0			598.18	0			0.003	0		
	1	3,150	3,150	Diesel Generators	80.0%	2,520		3.81	33,587			5.00	44,100			0.00	11			1.55	13,649			0.14	1,257			0.16	1,389			666.45	5,878,071			0.003	24		
				Total					33,587	21	2.67		44,100	28	3.50		11	0	0.00		13,649	9	1.08		1,257	1	0.10		1,389	1	0.11		5,878,071	3,702	466.51		24	0.02	0.00
Near-Terminal Op.: Maneuvering OUT	2	16,700	33,400	Main Engines	15.0%	5,010	1.0	6.24	31,269			6.60	33,066			0.01	30			2.64	13,226			0.19	945			0.21	1,057			646.03	3,236,622			0.003	14		
	1	3,150	3,150	Diesel Generators	80.0%	2,520		3.81	9,596			5.00	12,600			0.00	3			1.55	3,900			0.14	359			0.16	397			666.45	1,679,449			0.003	7		
				Total					40,865	90	11.35		45,666	101	12.69		33	0	0.01		17,126	38	4.76		1,304	3	0.36		1,454	3	0.40		4,916,070	10,838	1,365.58		21	0.05	0.01
Far-Terminal Op.: Maneuvering OUT	2	16,700	33,400	Main Engines	15.0%	5,010	1.0	6.24	31,269			6.60	33,066			0.01	30			2.64	13,226			0.19	945			0.21	1,057			646.03	3,236,622			0.003	14		
	1	3,150	3,150	Diesel Generators	80.0%	2,520		3.81	9,596			5.00	12,600			0.00	3			1.55	3,900			0.14	359			0.16	397			666.45	1,679,449			0.003	7		
				Total					40,865	90	11.35		45,666	101	12.69		33	0	0.01		17,126	38	4.76		1,304	3	0.36		1,454	3	0.40		4,916,070	10,838	1,365.58		21	0.05	0.01
Departure OUT	2	16,700	33,400	Main Engines	25.0%	8,350	2.0	5.89	98,330			5.00	83,500			0.01	91			2.00	33,400			0.17	2,839			0.19	3,173			598.18	9,989,573			0.003	46		
	1	3,150	3,150	Diesel Generators	80.0%	2,520		3.81	19,192			5.00	25,200			0.00	7			1.55	7,799			0.14	718			0.16	794			666.45	3,358,898			0.003	14		
				Total					117,522	130	16.32		108,700	120	15.10		97	0	0.01		41,199	45	5.72		3,557	4	0.49		3,967	4	0.55		13,348,471	14,714	1,853.95		60	0.07	0.01
Cruising OUT	2	16,700	33,400	Main Engines	80.0%	26,720	0.8	5.89	117,996			5.00	100,200			0.01	109			2.00	40,080			0.17	3,407			0.19	3,808			598.18	11,987,487			0.003	56		
	3	3,150	9,450	Diesel Generators	80.0%	7,560		3.81	21,591			5.00	28,350			0.00	7			1.55	8,774			0.14	808			0.16	893			666.45	3,778,760			0.003	16		
				Total					139,587	410	51.70		128,550	378	47.61		116	0	0.04		48,854	144	18.09		4,215	12	1.56		4,701	14	1.74		15,766,247	46,344	5,839.35		71	0.21	0.03
					Total Call Time (hr)		34.50																																

TOTAL (g/Call)	1,217,119				1,365,464				742				467,831				40,948				45,460				172,302,741		

MEC-13 MAIN ENGINES – STEAM – NORMAL ARRIVAL

Calls Per Year3.95

Mode	Number of Boilers Operating	Number of Steam Turbine Operating	Number of Generators Operating	Total Output Power (kiw)	Load Factor	Utilized Power (kW)	Time in Mode (hr)	NOx				CO				SOx				VOC				PM2.5				PM10				GHG (CO2E)				HAPs					
								Factor (g/kW-hr)	Mass Emitted (g)	Emission Rate	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)		
Cruise IN (25nm radius from terminal)	2	1	1	37,000	82.0%	30,340	0.8	2.00	45,510			0.2	4,551			0.57	12,970			0.1	2,276			0.15	3,413			0.17	3,868			922.97	21,002,182			0.003	63				
				Total					45,510	134	16.9		4,551	13	2		12,970	38	4.8		2,276	7	1		3,413	10	1		3,868	11	1		21,002,182	61,735	7,779		63	0.19	0.02		
Approach IN	2	1	1	37,000	20.0%	7,400	2.0	2.00	29,600			0.2	2,960			0.57	8,436			0.1	1,480			0.15	2,220			0.17	2,516			922.97	13,659,956			0.003	41				
				Total					29,600	33	4.1		2,960	3	0		8,436	9	1.2		1,480	2	0		2,220	2	0		2,516	3	0		13,659,956	15,057	1,897		41	0.05	0.01		
Far-Terminal Op.: Maneuvering IN	2	1	1	37,000	25.0%	9,250	1.0	2.00	18,500			0.2	1,850			0.57	5,273			0.1	925			0.15	1,388			0.17	1,573			922.97	8,537,473			0.003	41				
				Total					18,500	41	5.1		1,850	4	1		5,273	12	1.5		925	2	0		1,388	3	0		1,573	3	0		8,537,473	18,822	2,372		41	0.09	0.01		
Near-Terminal Op.: Maneuvering IN	2	1	1	37,000	25.0%	9,250	1.0	2.00	18,500			0.2	1,850			0.57	5,273			0.1	925			0.15	1,388			0.17	1,573			922.97	8,537,473			0.003	26				
				Total					18,500	41	5.1		1,850	4	1		5,273	12	1.5		925	2	0		1,388	3	0		1,573	3	0		8,537,473	18,822	2,372		26	0.06	0.01		
Cool Down	1	0	1	37,000	13.5%	5,000	3.5	2.22	38,850			0.304	5,320			0.6498	11,372			0.152	2,660			0.1785	3,124			0.2023	3,540			1052.19	18,413,252			0.003	49				
				Total					38,850	24	3.1		5,320	3	0		11,372	7	0.9		2,660	2	0		3,124	2	0		3,540	2	0		18,413,252	11,598	1,461		49	0.03	0.00		
Loading	1	0	2	37,000	13.5%	5,000	18.00	2.22	199,800			0.304	27,360			0.6498	58,482			0.152	13,680			0.1785	16,065			0.2023	18,207			1052.19	94,696,722			0.003	250				
				Total					199,800	24	3.1		27,360	3	0.42		58,482	7	0.90		13,680	2	0		16,065	2	0.25		18,207	2	0		94,696,722	11,598	1,461		250	0.03	0.00		
Hoteling	1	0	2	37,000	13.5%	5,000	18.00	2.22	199,800			0.304	27,360			0.6498	58,482			0.152	13,680			0.1785	16,065			0.2023	18,207			1052.19	94,696,722			0.003	250				
				Total					199,800	24	3.1		27,360	3	0		58,482	7	0.90		13,680	2	0		16,065	2	0		18,207	2	0		94,696,722	11,598	1,461		250	0.03	0.00		
Purge Lines	1	0	1	37,000	13.5%	5,000	3.5	2.22	38,850			0.304	5,320			0.6498	11,372			0.152	2,660			0.1785	3,124			0.2023	3,540			1052.19	18,413,252			0.003	49				
				Total					38,850	24	3.1		5,320	3	0		11,372	7	0.9		2,660	2	0		3,124	2	0		3,540	2	0		18,413,252	11,598	1,461		49	0.03	0.00		
Near-Terminal Op.: Maneuvering OUT	1	0	1	37,000	25.0%	9,250	1.0	2.00	18,500			0.2	1,850			0.57	5,273			0.1	925			0.15	1,388			0.17	1,573			922.97	8,537,473			0.003	26				
				Total					18,500	41	5.1		1,850	4	1		5,273	12	1.5		925	2	0		1,388	3	0		1,573	3	0		8,537,473	18,822	2,372		26	0.06	0.01		
Far-Terminal Op.: Maneuvering OUT	1	0	1	37,000	25.0%	9,250	1.0	2.00	18,500			0.2	1,850			0.57	5,273			0.1	925			0.15	1,388			0.17	1,573			922.97	8,537,473			0.003	26				
				Total					18,500	41	5.1		1,850	4	1		5,273	12	1.5		925	2	0		1,388	3	0		1,573	3	0		8,537,473	18,822	2,372		26	0.06	0.01		
Departure OUT	2	1	1	37,000	20.0%	7,400	2.0	2.00	29,600			0.2	2,960			0.57	8,436			0.1	1,480			0.15	2,220			0.17	2,516			922.97	13,659,956			0.003	41				
				Total					29,600	33	4.1		2,960	3	0		8,436	9	1.2		1,480	2	0		2,220	2	0		2,516	3	0		13,659,956	15,057	1,897		41	0.05	0.01		
Cruising OUT	2	1	1	37,000	82.0%	30,340	0.8	2.00	45,510			0.2	4,551			0.57	12,970			0.1	2,276			0.15	3,413			0.17	3,868			922.97	21,002,182			0.003	63				
				Total					45,510	134	16.9		4,551	13	2		12,970	38	4.8		2,276	7	1		3,413	10	1		3,868	11	1		21,002,182	61,735	7,779		63	0.19	0.02		
Total Call Time (hr)								32.50																																	
TOTAL (g/Call)									701,520				87,782				203,610				43,891				55,194				62,553				329,694,114				922				
TOTAL (kg/year)									2,770				347				804				173				218				247				1,301,601				4				
Weighted Average (lb/hr - g/s)										34.0	4.3			4.1	0.5			9.8	1.2		2.0	0.3			2.7	0.3			3.0	0.4			15940.7	2008.5			0.05	0.01			
Total Emissions (tpy)									3.1				0.4				0.9				0.2				0.2				0.3				1434.7				0.0				

Calls Per Year		5.98		THESE VESSELS REQUIRE ADDITIONAL GAS UP AND COOL DOWN TIME BEFORE LNG LOADING CAN OCCUR (24 HOURS FOR GAS UP AND 24 HOURS FOR COOL DOWN)																																			
Mode	Number of Engines	Power (kW) per Engine	Total Power (kW)		Load Factor	Utilized Power (kW)	Time in Mode (hr)	NOx				CO				SOx				VOC				PM2.5				PM10				GHG (CO2E)				HAPs			
								Factor (g/kW-hr)	Mass Entitled (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Entitled (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Entitled (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Entitled (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Entitled (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Entitled (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Entitled (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Entitled (g)	Emission Rate (lb/hr)	Emission Rate (g/s)
Cruising IN	2	16,700	33,400	Main Engines	80.0%	26,720	0.8	5.89	117,996			5.00	100,200			0.01	109			2.00	40,080			0.17	3,407			0.19	3,808			598.18	11,987,487			0.003	56		
	3	3,150	9,450	Diesel Generators	80.0%	7,560		3.81	21,591			5.00	28,350			0.00	7			1.55	8,774			0.14	893			0.16	893			666.45	3,778,760			0.003	16		
	Total																																						
									139,587	410	51.70		128,550	378	47.61		116	0	0.04		48,854	144	18.09		4,215	12	1.56		4,701	14	1.74		15,766,247	46,344	5,839.35		71	0.21	0.03
Approach IN	2	16,700	33,400	Main Engines	25.0%	8,350	2.0	5.89	98,330			5.00	83,500			0.01	91			2.00	33,400			0.17	2,839			0.19	3,173			598.18	9,989,573			0.003	46		
	1	3,150	3,150	Diesel Generators	80.0%	2,520		3.81	19,192			5.00	25,200			0.00	7			1.55	7,799			0.14	718			0.16	794			666.45	3,358,898			0.003	14		
	Total																																						
									117,522	130	16.32		108,700	120	15.10		97	0	0.01		41,199	45	5.72		3,557	4	0.49		3,967	4	0.55		13,348,471	14,714	1,853.95		60	0.07	0.01
Far-Terminal Op.: Maneuvering IN	2	16,700	33,400	Main Engines	15.0%	5,010	1.0	6.24	31,269			6.60	33,066			0.01	30			2.64	13,226			0.19	945			0.21	1,057			646.03	3,236,622			0.003	14		
	1	3,150	3,150	Diesel Generators	80.0%	2,520		3.81	9,596			5.00	12,600			0.00	3			1.55	3,900			0.14	359			0.16	397			666.45	1,679,449			0.003	7		
	Total																																						
									40,865	90	11.35		45,666	101	12.69		33	0	0.01		17,126	38	4.76		1,304	3	0.36		1,454	3	0.40		4,916,070	10,838	1,365.58		21	0.05	0.01
Near-Terminal Op.: Maneuvering IN	2	16,700	33,400	Main Engines	15.0%	5,010	1.0	6.24	31,269			6.60	33,066			0.01	30			2.64	13,226			0.19	945			0.21	1,057			646.03	3,236,622			0.003	14		
	1	3,150	3,150	Diesel Generators	80.0%	2,520		3.81	9,596			5.00	12,600			0.00	3			1.55	3,900			0.14	359			0.16	397			666.45	1,679,449			0.003	7		
	Total																																						
									40,865	90	11.35		45,666	101	12.69		33	0	0.01		17,126	38	4.76		1,304	3	0.36		1,454	3	0.40		4,916,070	10,838	1,365.58		21	0.05	0.01
Cool Down / Vessel Purge	2	16,700	33,400	Main Engines	Shut Down		48.0	5.89	0			5.00	0			0.01	0			2.00	0			0.17	0			0.19	0			598.18	0			0.003	0		
	1	3,150	3,150	Diesel Generators	80.0%	2,520		3.81	460,616			5.00	604,800			0.00	157			1.55	187,186			0.14	17,237			0.16	19,051			666.45	80,613,550			0.003	335		
	Total																																						
									460,616	21	2.67		604,800	28	3.50		157	0	0.00		187,186	9	1.08		17,237	1	0.10		19,051	1	0.11		80,613,550	3,702	466.51		335	0.02	0.00
LNG Loading	0	16,700	0	Main Engines	Shut Down		18.00	5.89	0			5.00	0			0.01	0			2.00	0			0.17	0			0.19	0			598.18	0			0.003	0		
	3	3,150	9,450	Diesel Generators	52.9%	5,000		3.81	342,720			5.00	450,000			0.00	117			1.55	139,275			0.14	12,825			0.16	14,175			666.45	59,980,320			0.003	250		
	Total																																						
									342,720	42	5.29		450,000	55	6.94		117	0	0.00		139,275	17	2.15		12,825	2	0.20		14,175	2	0.22		59,980,320	7,346	925.62		250	0.03	0.00
Hoteling	0	16,700	0	Main Engines	Shut Down		18.00	5.89	0			5.00	0			0.01	0			2.00	0			0.17	0			0.19	0			598.18	0			0.003	0		
	3	3,150	9,450	Diesel Generators	20.0%	1,890		3.81	129,548			5.00	170,100			0.00	44			1.55	52,646			0.14	4,848			0.16	5,358			666.45	22,672,561			0.003	94		
	Total																																						
									129,548	16	2.00		170,100	21	2.63		44	0	0.00		52,646	6	0.81		4,848	1	0.07		5,358	1	0.08		22,672,561	2,777	349.89		94	0.01	0.00
Line Purge/Prep	2	16,700	33,400	Main Engines	Shut Down		3.5	5.89	0			5.00	0			0.01	0			2.00	0			0.17	0			0.19	0			598.18	0			0.003	0		
	1	3,150	3,150	Diesel Generators	80.0%	2,520		3.81	33,587			5.00	44,100			0.00	11			1.55	13,649			0.14	1,257			0.16	1,389			666.45	5,878,071			0.003	24		
	Total																																						
									33,587	21	2.67		44,100	28	3.50		11	0	0.00		13,649	9	1.08		1,257	1	0.10		1,389	1	0.11		5,878,071	3,702	466.51		24	0.02	0.00
Near-Terminal Op.: Maneuvering OUT	2	16,700	33,400	Main Engines	15.0%	5,010	1.0	6.24	31,269			6.60	33,066			0.01	30			2.64	13,226			0.19	945			0.21	1,057			646.03	3,236,622			0.003	14		
	1	3,150	3,150	Diesel Generators	80.0%	2,520		3.81	9,596			5.00	12,600			0.00	3			1.55	3,900			0.14	359			0.16	397			666.45	1,679,449			0.003	7		
	Total																																						
									40,865	90	11.35		45,666	101	12.69		33	0	0.01		17,126	38	4.76		1,304	3	0.36		1,454	3	0.40		4,916,070	10,838	1,365.58		21	0.05	0.01
Far-Terminal Op.: Maneuvering OUT	2	16,700	33,400	Main Engines	15.0%	5,010	1.0	6.24	31,269			6.60	33,066			0.01	30			2.64	13,226			0.19	945			0.21	1,057			646.03	3,236,622			0.003	14		
	1	3,150	3,150	Diesel Generators	80.0%	2,520		3.81	9,596			5.00	12,600			0.00	3			1.55	3,900			0.14	359			0.16	397			666.45	1,679,449			0.003	7		
	Total																																						
									40,865	90	11.35		45,666	101	12.69		33	0	0.01		17,126	38	4.76		1,304	3	0.36		1,454	3	0.40		4,916,070	10,838	1,365.58		21	0.05	0.01
Departure OUT	2	16,700	33,400	Main Engines	25.0%	8,350	2.0	5.89	98,330			5.00	83,500			0.01	91			2.00	33,400			0.17	2,839			0.19	3,173			598.18	9,989,573			0.003	46		
	1	3,150	3,150	Diesel Generators	80.0%	2,520		3.81	19,192			5.00	25,200			0.00	7			1.55	7,799			0.14	718			0.16	794			666.45	3,358,898			0.003	14		
	Total																																						
									117,522	130	16.32		108,700	120	15.10		97	0	0.01		41,199	45	5.72		3,557	4	0.49		3,967	4	0.55		13,348,471	14,714	1,853.95		60	0.07	0.01
Cruising OUT	2	16,700	33,400	Main Engines	80.0%	26,720	0.8	5.89	117,996			5.00	100,200			0.01	109			2.00	40,080			0.17	3,407			0.19	3,808			598.18	11,987,487			0.003	56		
	3	3,150	9,450	Diesel Generators	80.0%	7,560		3.81	21,591			5.00	28,350			0.00	7			1.55	8,774			0.14	893			0.16	893			666.45	3,778,760			0.003	16		
	Total																																						
									139,587	410	51.70		128,550	378	47.61		116	0	0.04		48,854	144	18.09		4,215	12	1.56		4,701	14	1.74		15,766,247	46,344	5,839.35		71	0.21	0.03
					Total Call Time (hr)		79.00																																
								TOTAL (g/Call)				1,644,148																											

MEC-15 MAIN ENGINES – STEAM – WARM ARRIVAL

Calls Per Year		0.12		THESE VESSELS REQUIRE ADDITIONAL GAS UP AND COOL DOWN TIME BEFORE LNG LOADING CAN OCCUR (24 HOURS FOR GAS UP AND 24 HOURS FOR COOL DOWN)																																																			
Mode	Number of Boilers Operating	Number of Steam Turbine Operating	Number of Generators Operating	Total Output Power (kiwi)	Load Factor	Utilized Power (kW)	Time in Mode (hr)	NOx				CO				SOx				VOC				PM2.5				PM10				GHG (CO2E)				HAPs																			
								Factor (g/kW-hr)	Mass Emitted (g)	Emission Rate	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)																
Cruise IN (25nm radius from terminal)	2	1	1	37,000	82.0%	30,340	0.8	2.00	45,510			0.2	4,551			0.57	12,970			0.1	2,276			0.15	3,413			0.17	3,868			922.97	21,002,182			0.003	63																		
				Total					45,510	134	17		4,551	13	2		12,970	38	5		2,276	7	1		3,413	10	1		3,868	11	1		21,002,182	61,735	7,779		63	0.19	0.02																
Approach IN	2	1	1	37,000	20.0%	7,400	2.0	2.00	29,600			0.2	2,960			0.57	8,436			0.1	1,480			0.15	2,220			0.17	2,516			922.97	13,659,956			0.003	41																		
				Total					29,600	33	4		2,960	3	0		8,436	9	1		1,480	2	0		2,220	2	0		2,516	3	0		13,659,956	15,057	1,897		41	0.05	0.01																
Far-Terminal Op.: Maneuvering IN	2	1	1	37,000	25.0%	9,250	1.0	2.00	18,500			0.2	1,850			0.57	5,273			0.1	925			0.15	1,388			0.17	1,573			922.97	8,537,473			0.003	41																		
				Total					18,500	41	5		1,850	4	1		5,273	12	1		925	2	0		1,388	3	0		1,573	3	0		8,537,473	18,822	2,372		41	0.09	0.01																
Near-Terminal Op.: Maneuvering IN	2	1	1	37,000	25.0%	9,250	1.0	2.00	18,500			0.2	1,850			0.57	5,273			0.1	925			0.15	1,388			0.17	1,573			922.97	8,537,473			0.003	26																		
				Total					18,500	41	5		1,850	4	1		5,273	12	1		925	2	0		1,388	3	0		1,573	3	0		8,537,473	18,822	2,372		26	0.06	0.01																
Cool Down	1	0	1	37,000	13.5%	5,000	48.0	2.22	532,800			0.304	72,960			0.6498	155,952			0.152	36,480			0.1785	42,840			0.2023	48,552			1052.19	252,524,592			0.003	666																		
				Total					532,800	24	3		72,960	3	0		155,952	7	1		36,480	2	0		42,840	2	0		48,552	2	0		252,524,592	11,598	1,461		666	0.03	0.00																
Loading	1	0	2	37,000	13.5%	5,000	18.00	2.22	199,800			0.304	27,360			0.6498	58,482			0.152	13,680			0.1785	16,065			0.2023	18,207			1052.19	94,696,722			0.003	250																		
				Total					199,800	24	3		27,360	3	0		58,482	7	1		13,680	2	0		16,065	2	0		18,207	2	0		94,696,722	11,598	1,461		250	0.03	0.00																
Hoteling	1	0	2	37,000	13.5%	5,000	18.00	2.22	199,800			0.304	27,360			0.6498	58,482			0.152	13,680			0.1785	16,065			0.2023	18,207			1052.19	94,696,722			0.003	250																		
				Total					199,800	24	3		27,360	3	0		58,482	7	1		13,680	2	0		16,065	2	0		18,207	2	0		94,696,722	11,598	1,461		250	0.03	0.00																
Purge Lines	1	0	1	37,000	13.5%	5,000	3.5	2.22	38,850			0.304	5,320			0.6498	11,372			0.152	2,660			0.1785	3,124			0.2023	3,540			1052.19	18,413,252			0.003	49																		
				Total					38,850	24	3		5,320	3	0		11,372	7	1		2,660	2	0		3,124	2	0		3,540	2	0		18,413,252	11,598	1,461		49	0.03	0.00																
Near-Terminal Op.: Maneuvering OUT	1	0	1	37,000	25.0%	9,250	1.0	2.00	18,500			0.2	1,850			0.57	5,273			0.1	925			0.15	1,388			0.17	1,573			922.97	8,537,473			0.003	26																		
				Total					18,500	41	5		1,850	4	1		5,273	12	1		925	2	0		1,388	3	0		1,573	3	0		8,537,473	18,822	2,372		26	0.06	0.01																
Far-Terminal Op.: Maneuvering OUT	1	0	1	37,000	25.0%	9,250	1.0	2.00	18,500			0.2	1,850			0.57	5,273			0.1	925			0.15	1,388			0.17	1,573			922.97	8,537,473			0.003	26																		
				Total					18,500	41	5		1,850	4	1		5,273	12	1		925	2	0		1,388	3	0		1,573	3	0		8,537,473	18,822	2,372		26	0.06	0.01																
Departure OUT	2	1	1	37,000	20.0%	7,400	2.0	2.00	29,600			0.2	2,960			0.57	8,436			0.1	1,480			0.15	2,220			0.17	2,516			922.97	13,659,956			0.003	41																		
				Total					29,600	33	4		2,960	3	0		8,436	9	1		1,480	2	0		2,220	2	0		2,516	3	0		13,659,956	15,057	1,897		41	0.05	0.01																
Cruising OUT	2	1	1	37,000	82.0%	30,340	0.8	2.00	45,510			0.2	4,551			0.57	12,970			0.1	2,276			0.15	3,413			0.17	3,868			922.97	21,002,182			0.003	63																		
				Total					45,510	134	17		4,551	13	2		12,970	38	5		2,276	7	1		3,413	10	1		3,868	11	1		21,002,182	61,735	7,779		63	0.19	0.02																
					Total Call Time (hr)		77.00																																																
TOTAL (g/Call)								1,195,470						155,422						348,190						77,711						94,910				107,565						563,805,454				1,539									
TOTAL (kg/year)								146						19						43						9						12				13				68,841				0											
Weighted Average (lb/hr - g/s)										28.5		3.6				3.7		0.5				8.3		1.0				1.8		0.2				2.3		0.3				2.6		0.3				13431.0		1692.3				0.037		0.005	
Total Emissions (tpy)								0.2						0.0						0.0						0.0				0.0				0.0				75.9				0.0				0.037		0.005							

MEC-16 CARRIER TUGS – NORMAL CARRIER ARRIVAL – NON-ICE MANAGEMENT

Call Per Year		100																																				
Mode	Tug Operation	Tug Name	Power (kW)	Load Factor	Utilized Power (kW)	Time in Mode (hr)	NOx				CO				SOx				VOC				PM2.5				PM10				GHG (CO2E)				HAPs			
							(g/kW-hr)	Mass Emitted (g)	Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Emitted (g)	Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Emitted (g)	Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)
LNG Carrier transits state waters	Dispatch/Idle	Tug 1	4,868	10.0%	487	4.0	2.20	4,276	2.36	0.30	9.80	19,082	10.52	1.33	0.00	3	0.00	0.00	0.37	725	0.40	0.05	0.08	161	0.09	0.01	0.08	161	0.09	0.01	874.24	1,702,240	938.20	118.21	0.003	5	0.00	0.00
		Tug 2	4,868	0.0%	0			0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00
		Tug 3	4,868	0.0%	0			0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00
	Total						0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00	
Approach Cruise IN	Dispatch/Idle	Tug 1	4,868	75.0%	3,651	1.0	1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 2	4,868	10.0%	487		2.20	1,069	2.36	0.30	9.80	4,770	10.52	1.33	0.00	1	0.00	0.00	0.37	181	0.40	0.05	0.08	40	0.09	0.01	0.08	40	0.09	0.01	874.24	425,560	938.20	118.21	0.003	1	0.00	0.00
		Tug 3	4,868	10.0%	487		2.20	1,069	2.36	0.30	9.80	4,770	10.52	1.33	0.00	1	0.00	0.00	0.37	181	0.40	0.05	0.08	40	0.09	0.01	0.08	40	0.09	0.01	874.24	425,560	938.20	118.21	0.003	1	0.00	0.00
		Tug 4	4,868	10.0%	487		2.20	1,069	2.36	0.30	9.80	4,770	10.52	1.33	0.00	1	0.00	0.00	0.37	181	0.40	0.05	0.08	40	0.09	0.01	0.08	40	0.09	0.01	874.24	425,560	938.20	118.21	0.003	1	0.00	0.00
Far-Terminal Op.: Maneuvering IN	Connect Towlines/ Positioning	Tug 1	4,868	75.0%	3,651	1.0	1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 2	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 3	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 4	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
Near-Terminal Op.: Maneuvering IN	Connect Towlines/ Positioning	Tug 1	4,868	75.0%	3,651	1.0	1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 2	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 3	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 4	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
Carrier Guarding / Ice Clearing	Carrier Guarding / Ice Clearing	Tug 1	4,868	75.0%	3,651	25.0	1.80	164,288	14.49	1.83	5.00	456,356	40.24	5.07	0.00	119	0.04	0.01	0.19	17,342	1.53	0.19	0.06	5,476	0.48	0.06	0.06	5,476	0.48	0.06	699.39	63,834,017	5,629.23	709.27	0.003	253	0.02	0.00
		Tug 2	4,868	10.0%	487		2.20	26,724	2.36	0.30	9.80	119,261	10.52	1.33	0.00	20	0.00	0.00	0.37	4,532	0.40	0.05	0.08	1,008	0.09	0.01	0.08	1,008	0.09	0.01	874.24	10,639,003	938.20	118.21	0.003	34	0.00	0.00
		Tug 3	4,868	10.0%	487		2.20	26,724	2.36	0.30	9.80	119,261	10.52	1.33	0.00	20	0.00	0.00	0.37	4,532	0.40	0.05	0.08	1,008	0.09	0.01	0.08	1,008	0.09	0.01	874.24	10,639,003	938.20	118.21	0.003	34	0.00	0.00
		Tug 4	4,868	10.0%	487		2.20	26,724	2.36	0.30	9.80	119,261	10.52	1.33	0.00	20	0.00	0.00	0.37	4,532	0.40	0.05	0.08	1,008	0.09	0.01	0.08	1,008	0.09	0.01	874.24	10,639,003	938.20	118.21	0.003	34	0.00	0.00
Near-Terminal Op.: Maneuvering OUT	Pull LNGC Away	Tug 1	4,868	75.0%	3,651	1.0	1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 2	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 3	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 4	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
Far-Terminal Op.: Maneuvering OUT	Pull LNGC Away	Tug 1	4,868	75.0%	3,651	1.0	1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 2	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 3	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 4	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
Departure OUT	Dismissed/Idle	Tug 1	4,868	75.0%	3,651	1.0	1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 2	4,868	10.0%	487		2.20	1,069	2.36	0.30	9.80	4,770	10.52	1.33	0.00	1	0.00	0.00	0.37	181	0.40	0.05	0.08	40	0.09	0.01	0.08	40	0.09	0.01	874.24	425,560	938.20	118.21	0.003</			

MEC-17 CARRIER TUGS – WARM CARRIER ARRIVAL – NON-ICE MANAGEMENT

Call Per Year		3		THESE VESSELS REQUIRE ADDITIONAL GAS UP AND COOL DOWN TIME BEFORE LNG LOADING CAN OCCUR (24 HOURS FOR GAS UP AND 24 HOURS FOR COOL DOWN)																																								
Mode	Tug Operation	Tug Name	Power (kW)	Load Factor	Utilized Power (kW)	Time in Mode (hr)	NOx				CO				SOx				VOC				PM2.5				PM10				GHG (CO2E)				HAPs									
							(g/kW-hr)	Mass Emitted (g)	Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Emitted (g)	Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Emitted (g)	Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)						
LNG Carrier transits state waters	Dispatch/Idle	Tug 1	4,868	10.0%	487	4.0	2.20	4,276	2.36	0.30	9.80	19,082	10.52	1.33	0.00	3	0.00	0.00	0.37	725	0.40	0.05	0.08	161	0.09	0.01	0.08	161	0.09	0.01	0.08	161	0.09	0.01	0.08	161	0.09	0.01	0.08					
		Tug 2	4,868	0.0%	0			0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00						
		Tug 3	4,868	0.0%	0			0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00						
		Tug 4	4,868	0.0%	0			0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00						
	Total						4,276	2.36	0.30		19,082	10.52	1.33		3	0.00	0.00		725	0.40	0.05		161	0.09	0.01		161	0.09	0.01		161	0.09	0.01		1,702,240	938.20	118.21		5	0.00	0.00			
Approach Cruise IN	Dispatch/Idle	Tug 1	4,868	75.0%	3,651	1.0	1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	0.06	219	0.48	0.06	0.06	219	0.48	0.06	0.06					
		Tug 2	4,868	10.0%	487		2.20	1,069	2.36	0.30	9.80	4,770	10.52	1.33	0.00	1	0.00	0.00	0.37	181	0.40	0.05	0.08	40	0.09	0.01	0.08	40	0.09	0.01	0.08	40	0.09	0.01	0.08	40	0.09	0.01	0.08					
		Tug 3	4,868	10.0%	487		2.20	1,069	2.36	0.30	9.80	4,770	10.52	1.33	0.00	1	0.00	0.00	0.37	181	0.40	0.05	0.08	40	0.09	0.01	0.08	40	0.09	0.01	0.08	40	0.09	0.01	0.08	40	0.09	0.01	0.08					
		Tug 4	4,868	10.0%	487		2.20	1,069	2.36	0.30	9.80	4,770	10.52	1.33	0.00	1	0.00	0.00	0.37	181	0.40	0.05	0.08	40	0.09	0.01	0.08	40	0.09	0.01	0.08	40	0.09	0.01	0.08	40	0.09	0.01	0.08					
	Total						9,778	21.56	2.72		32,566	71.80	9.05		7	0.02	0.00		1,237	2.73	0.34		340	0.75	0.09		340	0.75	0.09		340	0.75	0.09		3,830,041	8,443.84	1,063.90		14	0.03	0.00			
Far-Terminal Op.: Maneuvering IN	Connect Towlines/ Positioning	Tug 1	4,868	75.0%	3,651	1.0	1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	0.06	219	0.48	0.06	0.06	219	0.48	0.06	0.06					
		Tug 2	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	0.06	219	0.48	0.06	0.06	219	0.48	0.06	0.06					
		Tug 3	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	0.06	219	0.48	0.06	0.06	219	0.48	0.06	0.06					
		Tug 4	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	0.06	219	0.48	0.06	0.06	219	0.48	0.06	0.06					
	Total						26,286	57.95	7.30		73,017	160.98	20.28		19	0.04	0.01		2,775	6.12	0.77		876	1.93	0.24		876	1.93	0.24		876	1.93	0.24		10,213,443	22,516.90	2,837.07		40	0.09	0.01			
Near-Terminal Op.: Maneuvering IN	Connect Towlines/ Positioning	Tug 1	4,868	75.0%	3,651	1.0	1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	0.06	219	0.48	0.06	0.06	219	0.48	0.06	0.06					
		Tug 2	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	0.06	219	0.48	0.06	0.06	219	0.48	0.06	0.06					
		Tug 3	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	0.06	219	0.48	0.06	0.06	219	0.48	0.06	0.06					
		Tug 4	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	0.06	219	0.48	0.06	0.06	219	0.48	0.06	0.06					
	Total						26,286	57.95	7.30		73,017	160.98	20.28		19	0.04	0.01		2,775	6.12	0.77		876	1.93	0.24		876	1.93	0.24		876	1.93	0.24		10,213,443	22,516.90	2,837.07		40	0.09	0.01			
Carrier Guarding / Ice Clearing	Carrier Guarding / Ice Clearing	Tug 1	4,868	75.0%	3,651	55.0	1.80	361,434	14.49	1.83	5.00	1,003,984	40.24	5.07	0.00	261	0.01	0.00	0.19	38,151	1.53	0.19	0.06	12,048	0.48	0.06	0.06	12,048	0.48	0.06	0.06	12,048	0.48	0.06	0.06	699.39	140,434,837	5,629.23	709.27	0.003	557	0.02	0.00	
		Tug 2	4,868	10.0%	487		2.20	58,793	2.36	0.30	9.80	262,374	10.52	1.33	0.00	44	0.00	0.00	0.37	9,970	0.40	0.05	0.08	2,217	0.09	0.01	0.08	2,217	0.09	0.01	0.08	2,217	0.09	0.01	0.08	874.24	23,405,806	938.20	118.21	0.003	74	0.00	0.00	
		Tug 3	4,868	10.0%	487		2.20	58,793	2.36	0.30	9.80	262,374	10.52	1.33	0.00	44	0.00	0.00	0.37	9,970	0.40	0.05	0.08	2,217	0.09	0.01	0.08	2,217	0.09	0.01	0.08	2,217	0.09	0.01	0.08	874.24	23,405,806	938.20	118.21	0.003	74	0.00	0.00	
		Tug 4	4,868	10.0%	487		2.20	58,793	2.36	0.30	9.80	262,374	10.52	1.33	0.00	44	0.00	0.00	0.37	9,970	0.40	0.05	0.08	2,217	0.09	0.01	0.08	2,217	0.09	0.01	0.08	2,217	0.09	0.01	0.08	874.24	23,405,806	938.20	118.21	0.003	74	0.00	0.00	
	Total						537,814	21.56	2.72		1,791,107	71.80	9.05		393	0.02	0.00		68,062	2.73	0.34		18,698	0.75	0.09		18,698	0.75	0.09		18,698	0.75	0.09		210,652,256	8,443.84	1,063.90		780	0.03	0.00			
Near-Terminal Op.: Maneuvering OUT	Pull LNGC Away	Tug 1	4,868	75.0%	3,651	1.0	1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	0.06	219	0.48	0.06	0.06	219	0.48	0.06	0.06					
		Tug 2	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	0.06	219	0.48	0.06	0.06	219	0.48	0.06	0.06					
		Tug 3	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	0.06	219	0.48	0.06	0.06	219	0.48	0.06	0.06					
		Tug 4	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	0.06	219	0.48	0.06	0.06	219	0.48	0.06	0.06					
	Total						26,286	57.95	7.30		73,017	160.98	20.28		19	0.04	0.01		2,775	6.12	0.77		876	1.93	0.24		876	1.93	0.24		876	1.93	0.24		10,213,443	22,516.90	2,837.07		40	0.09	0.01			
Far-Terminal Op.: Maneuvering OUT	Pull LNGC Away	Tug 1	4,																																									

MEC-18 CARRIER TUGS – NORMAL CARRIER ARRIVAL – ICE MANAGEMENT

Call Per Year		98																																					
Mode	Tug Operation	Tug Name	Power (kW)	Load Factor	Utilized Power (kW)	Time in Mode (hr)	NOx				CO				SOx				VOC				PM2.5				PM10				GHG (CO2E)				HAPs				
							(g/kW-hr)	Mass Emitted (g)	Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Emitted (g)	Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Emitted (g)	Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)					
LNG Carrier transits state waters	Dispatch/Idle Ice Clearing	Tug 1	4,868	10.0%	487	4.0	2.20	4,276	2.36	0.30	9.80	19,082	10.52	1.33	0.00	3	0.00	0.00	0.37	725	0.40	0.05	0.08	161	0.09	0.01	0.08	161	0.09	0.01	0.08	874.24	1,702,240	938.20	118.21	0.003	5	0.00	0.00
		Tug 2	4,868	75.0%	3,651		1.80	26,286	14.49	1.83	5.00	73,017	40.24	5.07	0.00	19	0.01	0.00	0.19	2,775	1.53	0.19	0.06	876	0.48	0.06	0.06	876	0.48	0.06	0.06	699.39	10,213,443	5,629.23	709.27	0.003	40	0.02	0.00
		Tug 3	4,868	0.0%	0			0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00	
		Tug 4	4,868	0.0%	0			0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00	
	Total						30,562	16.84	2.12		92,099	50.76	6.40		22	0.01	0.00		3,500	1.93	0.24		1,037	0.57	0.07		1,037	0.57	0.07		11,915,683	6,567.43	827.48		46	0.03	0.00		
Approach Cruise IN	Dispatch/Idle Ice Clearing	Tug 1	4,868	75.0%	3,651	1.0	1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 2	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 3	4,868	10.0%	487		2.20	1,069	2.36	0.30	9.80	4,770	10.52	1.33	0.00	1	0.00	0.00	0.37	181	0.40	0.05	0.08	40	0.09	0.01	0.08	40	0.09	0.01	0.08	874.24	425,560	938.20	118.21	0.003	1	0.00	0.00
		Tug 4	4,868	10.0%	487		2.20	1,069	2.36	0.30	9.80	4,770	10.52	1.33	0.00	1	0.00	0.00	0.37	181	0.40	0.05	0.08	40	0.09	0.01	0.08	40	0.09	0.01	0.08	874.24	425,560	938.20	118.21	0.003	1	0.00	0.00
	Total						15,281	33.69	4.24		46,049	101.52	12.79		11	0.02	0.00		1,750	3.86	0.49		519	1.14	0.14		519	1.14	0.14		5,957,842	13,134.86	1,654.96		23	0.05	0.01		
Far-Terminal Op.: Maneuvering IN	Connect Towlines/ Positioning	Tug 1	4,868	75.0%	3,651	1.0	1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 2	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 3	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 4	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
	Total						26,286	57.95	7.30		73,017	160.98	20.28		19	0.04	0.01		2,775	6.12	0.77		876	1.93	0.24		876	1.93	0.24		10,213,443	22,516.90	2,837.07		40	0.09	0.01		
Near-Terminal Op.: Maneuvering IN	Connect Towlines/ Positioning	Tug 1	4,868	75.0%	3,651	1.0	1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 2	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 3	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 4	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
	Total						26,286	57.95	7.30		73,017	160.98	20.28		19	0.04	0.01		2,775	6.12	0.77		876	1.93	0.24		876	1.93	0.24		10,213,443	22,516.90	2,837.07		40	0.09	0.01		
Carrier Guarding / Ice Clearing	Carrier Guarding / Ice Clearing	Tug 1	4,868	75.0%	3,651	25.0	1.80	164,288	14.49	1.83	5.00	456,356	40.24	5.07	0.00	119	0.01	0.00	0.19	17,342	1.53	0.19	0.06	5,476	0.48	0.06	0.06	5,476	0.48	0.06	0.06	699.39	63,834,017	5,629.23	709.27	0.003	253	0.02	0.00
		Tug 2	4,868	75.0%	3,651		1.80	164,288	14.49	1.83	5.00	456,356	40.24	5.07	0.00	119	0.01	0.00	0.19	17,342	1.53	0.19	0.06	5,476	0.48	0.06	0.06	5,476	0.48	0.06	0.06	699.39	63,834,017	5,629.23	709.27	0.003	253	0.02	0.00
		Tug 3	4,868	10.0%	487		2.20	26,724	2.36	0.30	9.80	119,261	10.52	1.33	0.00	20	0.00	0.00	0.37	4,532	0.40	0.05	0.08	1,008	0.09	0.01	0.08	1,008	0.09	0.01	0.08	874.24	10,639,003	938.20	118.21	0.003	34	0.00	0.00
		Tug 4	4,868	10.0%	487		2.20	26,724	2.36	0.30	9.80	119,261	10.52	1.33	0.00	20	0.00	0.00	0.37	4,532	0.40	0.05	0.08	1,008	0.09	0.01	0.08	1,008	0.09	0.01	0.08	874.24	10,639,003	938.20	118.21	0.003	34	0.00	0.00
	Total						382,025	33.69	4.24		1,151,235	101.52	12.79		277	0.02	0.00		43,747	3.86	0.49		12,968	1.14	0.14		12,968	1.14	0.14		148,946,040	13,134.86	1,654.96		574	0.05	0.01		
Near-Terminal Op.: Maneuvering OUT	Pull LNGC Away	Tug 1	4,868	75.0%	3,651	1.0	1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 2	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 3	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 4	4,868	75.0%	3,651		1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
	Total						26,286	57.95	7.30		73,017	160.98	20.28		19	0.04	0.01		2,775	6.12	0.77		876	1.93	0.24		876	1.93	0.24		10,213,443	22,516.90	2,837.07		40	0.09	0.01		
Far-Terminal Op.: Maneuvering OUT	Pull LNGC Away	Tug 1	4,868	75.0%	3,651	1.0	1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	0.06	699.39							

MEC-19 CARRIER TUGS – WARM CARRIER ARRIVAL – ICE MANAGEMENT

Call Per Year					3		THESE VESSELS REQUIRE ADDITIONAL GAS UP AND COOL DOWN TIME BEFORE LNG LOADING CAN OCCUR (24 HOURS FOR GAS UP AND 24 HOURS FOR COOL DOWN)																																
Mode	Tug Operation	Tug Name	Power (kW)	Load Factor	Utilized Power (kW)	Time in Mode (hr)	NOx				CO				SOx				VOC				PM2.5				PM10				GHG (CO2E)				HAPs				
							(g/kW-hr)	Mass Emitted (g)	Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Emitted (g)	Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Emitted (g)	Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Mass Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	Factor (g/kW-hr)	Emitted (g)	Emission Rate (lb/hr)	Emission Rate (g/s)	
LNG Carrier transits state waters	Dispatch/Idle	Tug 1	4,868	10.0%	487	4.0	2.20	4,276	2.36	0.30	9.80	19,082	10.52	1.33	0.00	3	0.00	0.00	0.37	725	0.40	0.05	0.08	161	0.09	0.01	0.08	161	0.09	0.01	874.24	1,702,240	938.20	118.21	0.003	5	0.00	0.00	
		Tug 2	4,868	75.0%	3,651			0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00	
		Tug 3	4,868	0.0%	0			0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00	
		Tug 4	4,868	0.0%	0			0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00		0	0.00	0.00	
	Total						4,276	2.36	0.30		19,082	10.52	1.33		3	0.00	0.00		725	0.40	0.05		161	0.09	0.01		161	0.09	0.01		1,702,240	938.20	118.21		5	0.00	0.00		
Approach Cruise IN	Dispatch/Idle	Tug 1	4,868	75.0%	3,651	1.0	1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00	
		Tug 2	4,868	75.0%	3,651			1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 3	4,868	10.0%	487			2.20	1,069	2.36	0.30	9.80	4,770	10.52	1.33	0.00	1	0.00	0.00	0.37	181	0.40	0.05	0.08	40	0.09	0.01	0.08	40	0.09	0.01	874.24	425,560	938.20	118.21	0.003	1	0.00	0.00
		Tug 4	4,868	10.0%	487			2.20	1,069	2.36	0.30	9.80	4,770	10.52	1.33	0.00	1	0.00	0.00	0.37	181	0.40	0.05	0.08	40	0.09	0.01	0.08	40	0.09	0.01	874.24	425,560	938.20	118.21	0.003	1	0.00	0.00
	Total						15,281	33.69	4.24		46,049	101.52	12.79		11	0.02	0.00		1,750	3.86	0.49		519	1.14	0.14		519	1.14	0.14		5,957,842	13,134.86	1,654.96		23	0.05	0.01		
Far-Terminal Op.: Maneuvering IN	Connect Towlines/ Positioning	Tug 1	4,868	75.0%	3,651	1.0	1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00	
		Tug 2	4,868	75.0%	3,651			1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 3	4,868	75.0%	3,651			1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 4	4,868	75.0%	3,651			1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
	Total						26,286	57.95	7.30		73,017	160.98	20.28		19	0.04	0.01		2,775	6.12	0.77		876	1.93	0.24		876	1.93	0.24		10,213,443	22,516.90	2,837.07		40	0.09	0.01		
Near-Terminal Op.: Maneuvering IN	Connect Towlines/ Positioning	Tug 1	4,868	75.0%	3,651	1.0	1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00	
		Tug 2	4,868	75.0%	3,651			1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 3	4,868	75.0%	3,651			1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 4	4,868	75.0%	3,651			1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
	Total						26,286	57.95	7.30		73,017	160.98	20.28		19	0.04	0.01		2,775	6.12	0.77		876	1.93	0.24		876	1.93	0.24		10,213,443	22,516.90	2,837.07		40	0.09	0.01		
Carrier Guarding / Ice Clearing	Carrier Guarding / Ice Clearing	Tug 1	4,868	75.0%	3,651	55.0	1.80	361,434	14.49	1.83	5.00	1,003,984	40.24	5.07	0.00	261	0.01	0.00	0.19	38,151	1.53	0.19	0.06	12,048	0.48	0.06	0.06	12,048	0.48	0.06	699.39	140,434,837	5,629.23	709.27	0.003	557	0.02	0.00	
		Tug 2	4,868	75.0%	3,651			1.80	361,434	14.49	1.83	5.00	1,003,984	40.24	5.07	0.00	261	0.01	0.00	0.19	38,151	1.53	0.19	0.06	12,048	0.48	0.06	0.06	12,048	0.48	0.06	699.39	140,434,837	5,629.23	709.27	0.003	557	0.02	0.00
		Tug 3	4,868	10.0%	487			2.20	58,793	2.36	0.30	9.80	262,374	10.52	1.33	0.00	44	0.00	0.00	0.37	9,970	0.40	0.05	0.08	2,217	0.09	0.01	0.08	2,217	0.09	0.01	874.24	23,405,806	938.20	118.21	0.003	74	0.00	0.00
		Tug 4	4,868	10.0%	487			2.20	58,793	2.36	0.30	9.80	262,374	10.52	1.33	0.00	44	0.00	0.00	0.37	9,970	0.40	0.05	0.08	2,217	0.09	0.01	0.08	2,217	0.09	0.01	874.24	23,405,806	938.20	118.21	0.003	74	0.00	0.00
	Total						840,455	33.69	4.24		2,532,716	101.52	12.79		610	0.02	0.00		96,243	3.86	0.49		28,529	1.14	0.14		28,529	1.14	0.14		327,681,287	13,134.86	1,654.96		1,262	0.05	0.01		
Near-Terminal Op.: Maneuvering OUT	Pull LNGC Away	Tug 1	4,868	75.0%	3,651	1.0	1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00	
		Tug 2	4,868	75.0%	3,651			1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 3	4,868	75.0%	3,651			1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
		Tug 4	4,868	75.0%	3,651			1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23	709.27	0.003	10	0.02	0.00
	Total						26,286	57.95	7.30		73,017	160.98	20.28		19	0.04	0.01		2,775	6.12	0.77		876	1.93	0.24		876	1.93	0.24		10,213,443	22,516.90	2,837.07		40	0.09	0.01		
Far-Terminal Op.: Maneuvering OUT	Pull LNGC Away	Tug 1	4,868	75.0%	3,651	1.0	1.80	6,572	14.49	1.83	5.00	18,254	40.24	5.07	0.00	5	0.01	0.00	0.19	694	1.53	0.19	0.06	219	0.48	0.06	0.06	219	0.48	0.06	699.39	2,553,361	5,629.23						